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PROCEEDINGS OF THE SECOND STATIONARY SOURCE COMBUSTION SYMPOSIUM
Volume I. Small Industrial, Commercial, and Residential Systems

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16. ABSTRACT

The proceedings document the 50 presentations made during the Second Stationary Source Combustion Symposium held in New Orleans, LA, August 29-September 1, 1977. Sponsored by the Combustion Research Branch of EPA's Industrial Environmental Research Laboratory--RTP, the symposium dealt with subjects relating both to developing improved combustion technology for the reduction of air pollutant emissions from stationary sources, and to improving equipment efficiency. The symposium was divided into six parts, and the proceedings were issued in five volumes: Volume I--Small Industrial, Commercial, and Residential Systems; Volume II--Utility and Large Industrial Boilers; Volume III--Stationary Engine, Industrial Process Combustion Systems, and Advanced Processes; Volume IV--Fundamental Combustion Research; and Volume V--Addendum. The symposium was intended to provide contractor, industrial, and Government representatives with the latest information on EPA inhouse and contract combustion research projects related to pollution control, with emphasis on reducing nitrogen oxides while controlling other emissions and improving efficiency.

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Natural Gas, Nitrogen Oxides, Carbon	Combustion Modification	07B
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2. Environmental Protection Technology
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5. Socioeconomic Environmental Studies
6. Scientific and Technical Assessment Reports (STAR)
7. Interagency Energy-Environment Research and Development

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PROCEEDINGS OF THE SECOND STATIONARY SOURCE COMBUSTION SYMPOSIUM
Volume I. Small Industrial, Commercial, and Residential Systems

Symposium Chairman Joshua S. Bowen
Vice-Chairman Robert E. Hall

Environmental Protection Agency
Office of Research and Development
Industrial Environmental Research Laboratory
Research Triangle Park, North Carolina 27711

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PREFACE

These proceedings document the more than 60 presentations and discussions of the Second Symposium on Stationary Source Combustion held August 29 - September 1, 1977, at the Marriott Hotel in New Orleans, Louisiana. Sponsored by the Combustion Research Branch of the EPA's Industrial Environmental Research Laboratory-Research Triangle Park, the symposium presented the results of recent research in the areas of combustion processes, fuel properties, burner and furnace design, combustion modification, and emission control technology.

Dr. Joshua S. Bowen, Chief, Combustion Research Branch, was Symposium Chairman; Robert E. Hall, Combustion Research Branch, was Symposium Vice-Chairman and Project Officer. The Welcoming Address was delivered by Dr. John K. Burchard, Director of IERL-RTP; the Opening Address was delivered by Robert P. Hangebrauck, Director, Energy Assessment and Control Division, IERL-RTP; and Dr. Howard B. Mason, Program Manager NO_x Environmental Assessment Program, Acurex Corporation, delivered the Keynote Paper.

The symposium consisted of six sessions:

Session I: Small Industrial, Commercial and Residential Systems
Robert E. Hall, Session Chairman

Session II: Utility and Large Industrial Boilers
David G. Lachapelle, Session Chairman

Session III: Special Topics
David G. Lachapelle, Session Chairman

Session IV: Stationary Engine and Industrial Process Combustion Systems
John H. Wasser, Session Chairman

Session V: Advanced Processes
G. Blair Martin, Session Chairman

Session VI: Fundamental Combustion Research
W. Steven Lanier, Session Chairman

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OPENING ADDRESS

STATIONARY SOURCE COMBUSTION CONTROL -- ENVIRONMENTAL ENGINEERING R&D AT IERL-RTP

By:

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ABSTRACT

The purpose and outline of IERL-RTP's programs in the area of combustion assessment and control are presented, including environmental assessment and control technology development aspects. The energy (combustion) technologies covered are pointed out and the fuel use picture for these indicated. The applicable control approaches, including existing clean fuels, fuel cleaning, combustion modifications, and flue gas cleaning, are defined and examples of the emissions affected by these control approaches are given with emphasis on the air emission aspects. Each of the combustion control areas is discussed in terms of program activities and needs. Trends affecting the program, as well as some of the challenges, are discussed.

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ACKNOWLEDGMENTS

The author acknowledges the direct input and/or the availability of information developed by IERL-RTP personnel relating to program activities in the Utilities and Industrial Power Division (Bill Plyler, Director), and the Energy Assessment and Control Division (Branch Chiefs Josh Bowen, Kelly Janes, and Pic Turner). Also individual comments as input were provided by Josh Bowen, Bob Hall, Bill Rhodes, Wade Ponder, Bruce Henschel, and Stan Cuffe/John Copeland.

WHERE ARE THE CHALLENGES?--CONCLUSIONS

There are a lot of R&D challenges to the environmental engineer looking ahead at the energy/environmental area. Figure 1 lists a few key ones which relate to the status/trends of existing energy technologies and environmental engineering methodology development/evaluation. These are complex areas; however, I do believe we are on target in working toward the best environmental tools and focusing them on reality, in terms of the combustion/energy technologies which are here now and here to stay, and those that will shortly be in greater use.

Something soon becomes obvious to an environmental engineer working in this area. There are only a limited number of generic types of control systems available for application to a variety of stationary combustion sources, and while a particular control system may be aimed primarily at one type of pollutant, it invariably affects others. It is also soon obvious that combustion effluents are complex, multi-pollutant streams. It is further obvious that methods for evaluating the true impact of complex effluents are in the developmental stage. The need for such technologies (environmental assessment methodology) is of tremendous importance in doing the most economical job of applying the limited number of control approaches that we have, in combination, to produce truly the most environmentally effective results.

For example, consider the use of bioassays for effluent testing as an advanced environmental assessment tool. If coupling application of such techniques to the development of a combustion modification control for an oil-fired furnace results in eliminating the mutagenicity of particulates emitted and reduces the overall toxicity of the effluent by a factor of 10, or even to an undetectable level, we will have taken a considerable step forward in achieving true control effectiveness.

PURPOSE AND OUTLINE OF PROGRAM

IERL-RTP's program in combustion control is aimed at early definition of environmental problems and development of control technology. It is also a program aimed at identifying and/or providing for environmental alternatives as they relate to control approaches. There are two key activities in this program:

- Environmental assessment
- Control technology development

These two activities go hand in hand and are inseparable. Environmental assessment can be thought of not so much as the determination of the environmental acceptability of a particular energy process, as compared to some other energy process, but as the determination of the effective reduction in environmental emissions for one control option or one set of control options compared with other options. Thus what is really being evaluated is the environmental effectiveness of control or disposal options.

A more complete definition of environmental assessment is shown in Figures 2 and 3.

Control technology development on the other hand includes specific developmental activities which may be undertaken for one or more control approaches as depicted in Figure 4. These activities include basic and applied research and development (R&D), engineering analysis, and specific control process development/evaluation.

The central purpose behind the whole program is R&D support of the development of needed multi-media, multi-pollutant environmental regulations by identifying processes or sources for which regulations could be set, the technological options available for waste stream prevention or control, and potential new regulatory approaches for complex effluents.

Most combustion technology sources covered in the combustion-related part of IERL-RTP's program are indicated in Figure 5.

This paper, because of the orientation of our Symposium, is focused more on discussion of the air emission-control aspects of the control program areas shown in Figure 6.

PRESENT FUEL USE PICTURE

Figure 7 provides a summarized picture of U. S. stationary source fossil fuel consumption for 1974.(1) A look at the totals reveals that 38 percent of the consumption was gas, 30 percent oil, and 32 percent coal. It also can be discerned that over 57 percent of all fuel was combusted in other than utility boilers. The emphasis on increased coal use in the future will show up substantially in the utility boiler usage category as a practical means for supplying energy now and in the future to residential, commercial, and industrial sectors. Electrical energy has the environmental advantage of not creating additional pollutants during its utilization as an alternate to fuel burning in area type sources. Results of an EPA study published in March 1976, "EPA-600/2-76-049 a/b, Electrical Energy as an Alternate to Clean Fuels for Area Sources," are of interest here.(2)

APPLICABLE CONTROL APPROACHES

What are the control approaches applicable to combustion sources? Most of us have some degree of familiarity with the options, and Figure 8 is a listing of some of the main ones. Figure 9 gives an overview of the applicability of the general control approaches as they relate to categories of conventional combustion systems and advanced combustion systems. As can be seen, a considerable variability exists in the applicability of the general control approaches.

EMISSIONS AFFECTED BY CONTROL APPROACHES

For the purposes of this discussion, most of the air pollutants from combustion processes can be included in the two broad classes as indicated in Figure 10; that is, Inorganics and Organics. Each of these classes can be further broken into two groups: Gaseous and Particulate. Figure 10 also includes a brief list of some pollutants of concern under each of the groups indicated.

Perhaps the next question to ask is, "What classes of pollutants are controlled by the generally applicable control approaches?" It is desirable that control approaches be effective for a wide range of pollutants, but this is only partially possible in practice. It is suggested, however, in our further discussion that the advantage of "broad spectrum" control technologies (those that control a wide range of pollutants) be kept in mind as a means for maximizing cost effectiveness. Figure 11 builds on the pollutant groups defined in Figure 10 and attempts in a very simplified fashion to indicate the relationship of various control approaches to the types of pollutants of concern. Ideally, one would like to use the minimum number of broad spectrum control techniques to achieve effective control at a minimum of cost; this would truly be the most effective or "best control system" for the particular air pollution combustion source at hand. In the context of this paper a base case involves the use of a "dirty" fuel; therefore, a combination of control approaches is almost a necessity to achieve a "best control system" configuration--because most control processes are only partially effective for at least some of the general pollutant classes.

It should be further pointed out that the use of various control approaches can produce some additional pollutants. In Figure 11 the minuses (-) indicate a potential reduction in the pollutant; the pluses (+) indicate possible undesirable production of other pollutants. The illustration that Figure 11 provides is not an attempt at great accuracy or notation of all the subtleties of effects but to give an overview of control approach selectivity or lack thereof. Indeed, the only way this can be thoroughly addressed is through the application of comprehensive environmental assessment methodology. This is one reason why no entries were included for "Overall Effluent Acute Toxicity" in Figure 11.

Thus far we have few direct measurements of effluent toxicity. Approaches for making determinations in this area include as part of the environmental assessment: comprehensive chemical analyses, bioassays and environmental alternatives analysis.

One can conclude from study of Figure 11 that certain combinations look attractive for effecting some control of all classes of pollutants. Other reasons exist for using combinations, including the fact that cost can be reduced in some cases.

DISCUSSION OF CONTROL PROGRAM AREAS

The following discussion of control program areas is aimed at just covering the highlights. Many important facets are not included because of time limitations.

Existing Clean Fuels

IERL-RTP's program as it relates to existing clean fuels is primarily focused on coal and mainly low sulfur coal. Activities here as indicated in Figure 12 are environmental assessment, characterization of contaminant levels in various coals, R&D leading to enhancement in the usability of low-sulfur Western coals in conventional combustion systems, and use of Western coals in advanced combustion systems like fluid bed boilers.

Fuel contaminant studies are underway as part of projects with the Illinois State Geological Survey, U. S. Bureau of Mines, U. S. Geological Survey, and Battelle. Information developed and forthcoming should provide basic information of value in evaluating fuel resource applications and related environmental control needs. Such studies point to the problems of substantial variability in sulfur and other contaminant levels within various coal beds.

Efforts to enhance the usability of Western low-sulfur coals and lignite have included an already published study by Monsanto, "EPA-650/2-75-046, Evaluation of Low-Sulfur Western Coal Characteristics, Utilization, and Combustion Experience," (3) and another contract project with KVB which has focused on a series of mini-demonstrations of Western coal applications to the smaller area-source stoker-fired boilers where control alternatives were limited and less evaluation of low-sulfur Western coal use had been done. Other than usability and environmental difficulties, it is of interest here to determine the predictability with which the alkaline type ash in Western coal types combines with some portion of the fuel sulfur.

Use of the Western low-sulfur coals has also been examined for use in fluid bed combustors which have been shown to be capable of handling a wide variety of fuel types and in which conditions for utilization of alkaline ash in coal should be optimized. Studies in this area are being conducted by EPA and ERDA with encouraging results.

Fuel Cleaning

The major emphasis in IERL-RTP's program related to fuel cleaning is on coal with a lesser emphasis on residual oil. Figure 13 shows that the activities relating to coal cleaning include: physical cleaning, chemical cleaning, synthetic fuels, environmental assessment, and control technology development for fuel processes.

The physical coal cleaning program has an element concerned with the characterization of U. S. coals with respect to their cleanability. EPA-sponsored work in this area is primarily at the U. S. Bureau of Mines. The latest publication in this area is "EPA-600/2-76-091, Sulfur Reduction Potential of U. S. Coals: A Revised Report of Investigations." (4) Other work relating to this activity involves the U. S. Geological Survey. Another element of this program concerns the development/demonstration of physical coal cleaning technology. This work has led to a demonstration of coal cleaning as a control approach for SO_x at the Homer City complex, owned by the GPU Service Corp. and the New York State Electric and Gas Corp. This 50-million dollar cleaning facility utilizes a multiple-stream coal cleaning strategy (MCCS) to control approximately 1200 MW of existing capacity plus an additional new capacity of 600 MW which must meet New Source Performance Standards (NSPS). EPA's engineering support activity in the coal cleaning area has resulted in a new publication which should be of interest to those evaluating the use of coal cleaning, "EPA-600/2-76-138, Coal Preparation Environmental Engineering Manual."(5)

Chemical cleaning program activities have centered primarily on evaluation of alternative processes and pilot plant or bench scale support of some related processes. The TRW/Meyers ferric oxidation leaching process is now being evaluated at the pilot plant stage. The report, "EPA-650/2-74-025a, Applicability of the Meyers Process for Chemical Desulfurization of Coal: Survey of Thirty-Five Coals,"(6) includes data on removal of other contaminants from coal. Application and process improvement work is also underway on the Battelle Hydrothermal Cleaning Process. Other processes under evaluation include flash desulfurization, microwave processing, and microbial leaching.

Under EPA's environmental assessment program, environmental aspects associated with the processing/utilization of synthetic fuels as clean fuels are being evaluated for this type of more intensive coal refining. Several reports have been issued including, "EPA-600/2-76-101, Evaluation of Pollution Control in Fossil Fuel Conversion Processes: Final Report."(7) Because of the longer term development involved here, further discussion is not included.

Other environmental assessment and control technology development work aimed at problem definition and evaluation is underway in the coal cleaning area. Major contractors include BMI (environmental assessment) and Versar/Joy Denver (control technology development).

The residual-oil related program is aimed at environmentally sound use of residual oil through contaminant removal. Related to this is the problem of conversion of existing gas-fired power plant capacity to residual oil or coal fuels. EPA has sponsored the development/application of the Chemically Active Fluid Bed (CAFB) as a front-end/on-site desulfurization/demetallization process for residual oil or lignite. A demonstration plant is currently under construction on a small gas-fired utility boiler at the La Palma Station of Central Power and Light (CPL) in San Benito, Texas. Other techniques for cleanup of residual oil feedstocks have primarily focused on improved catalyst systems for HDS/HDN/demetallization and have involved projects at Hydrocarbon Research, Inc. (HRI) and MIT. Another important component of the overall program is environmental assessment of residual oil processing/utilization alternatives. Catalytic, Inc., is the major contractor here with additional work being done by another contractor on characterization of hazardous substances in residual oil.

Combustion Modifications Control

Figure 14 outlines the major elements of the combustion modifications control program. I am limiting the extent of coverage here since the material will be covered intensively as the subject of this Symposium. A major contractor, Aerotherm, is being used to provide environmental assessment and systems study support. Applications testings is being done by two contractors: Exxon for electric utilities and KVB for industrial combustion sources. This part of the program, in addition to providing various operation guideline manuals and design guideline manuals, will provide documentation on two or more detailed long-term corrosion tests on utility boilers under baseline and "low-NO_x" operation.

That part of the program aimed at utility and large industrial boilers has its primary emphasis on the development/application of low-emission coal burners for both industrial and utility boilers with a near-term goal of 0.3 lb $NO_x/10^6$ BTU (130 nanograms/joule). Important components of the program, aimed at small industrial, commercial and residential systems, are: application of optimum control technology for commercial package boilers (Ultrasystems), demonstration of the performance of a low-emission oil-fired residential furnace (Rocketdyne), and development of technology for control of stoker-fired coal boilers (Battelle). The part of the program aimed at afterburners and industrial combustors is limited to an environmental assessment of afterburner technology applications. Development of combustion modifications for other industrial combustors will be initiated when work on higher priority sources is further along. In the stationary engine area a major contractor, Pratt and Whitney, is focusing on CM approaches to achieve R&D goals of 50 ppm (at 15 percent O_2) for clean fuels and 100 ppm for fuels containing up to 0.5 percent bound nitrogen. The goals represent a 75 percent reduction from uncontrolled NO_x emissions. A major contractor is also just initiating work to develop control technology for large reciprocating engines. Fundamental combustion research studies are an important part of the program and are coordinated under a large contract aimed at defining optimum combustion control for all systems.

Combustion modifications based on advanced processes are an important part of the program. Attention is being focused on development of design criteria for an advanced, optimized, conventional utility combustion system (Ultrasystems), an initial application of catalytic combustion (Aerotherm), and burner design criteria for low-BTU gas.

EPA's program on fluidized bed combustion (FBC) over the past several years led to the breakthrough technology development of the use of a limestone/dolomite sorbent (in-process reactant for SO_2) as the primary fluidization material in FBC. Current work is focusing on environmental assessment and control technology development of the emerging FBC systems. EPA is working closely with ERDA in this area to assure that needed environmental testing and evaluation support is applied and independent environmental analysis is conducted leading to recommendations for standards. A good example of the cooperative effort is the work planned for the 30 MW Rivesville atmospheric fluidized-bed combustor built by ERDA.

The approach being taken in the FBC program, as in other energy technology areas, is to establish environmental goals for the FBC process based ultimately on health and ecological effects. Simultaneously, emissions data will be collected from comprehensive analysis on operating FBC units. By comparison of the goals with these measured emissions, the degree of control required will be identified, and a program will be designed to develop control technology to meet the established goals. Results will be used by IERL-RTP to assess the environmental impact of the FBC process to provide the data base for appropriate environmental standards for the process, to prepare manuals of best available control technology, and to design and conduct a program to develop any necessary control technology.

Aside from attention being given to particulate control, solid waste treatment/disposal, and other key areas, work is underway to define combustion modifications for the FBC process to minimize NO_x emissions. Advances in control of NO_x from conventional combustion systems, as a product of R&D in this area, can be projected to result in levels of NO_x which are lower than the moderately low levels from FBC units.

Flue Gas Cleaning

Figure 15 outlines the major elements of work in the area of flue gas cleaning, including particulate control, flue gas desulfurization, and flue gas treatment for NO_x.

The particulate control research program is directed toward assessing and extending the capabilities of conventional particulate control systems (electrostatic precipitators (ESP's), scrubbers, and fabric filters) to abate aerosol emissions. In addition, the program will explore new and improved control methods with potential for cost or performance advantages and will develop technology specific to existing and potential major particulate emission problems, such as low sulfur coal combustion, new fuel and power production, fugitive emissions, and other selected priority sources. Major elements of this program include effective application of conventional particulate control technology, fine particulate control for combustion processes utilizing low-sulfur fuels, development of new fine particulate control technology, development of high-temperature/high-pressure (HT/HP) particulate control, and technology transfer.

The flue gas desulfurization program area includes activities relating to non-regenerable processes, regenerable processes, technology transfer/supporting studies, and control of waste and water pollution from combustion systems. The non-regenerable program is focusing on lime/limestone technology development including the Shawnee alkali scrubbing test program, Louisville Gas and Electric's Paddy's Run lime scrubbing test program, application of FGD systems to industrial boilers, and a stack gas reheat assessment study. A second key portion of the non-regenerable program is a full scale demonstration of the double alkali process and development/demonstration of double alkali limestone regeneration techniques. In the area of regenerable processes primary attention is being given to demonstration of the Wellman-Lord/Allied process, a magnesium oxide test program, aqueous carbonate process demonstration, citrate process demonstration, and comparative economic studies at TVA. In the area of FGD technology transfer and supporting studies work is emphasizing engineering application/information transfer, flue gas cleaning decision models and data books, FGD process environmental assessment studies, and non-utility source studies. In the area of control of waste and water pollution from combustion sources, activities include assessment of flue gas cleaning disposal technology, by-product utilization, and development of water utilization/treatment technology for power plants.

Flue gas treatment for NO_x is the smallest part of the flue gas cleaning program area. It is being given attention, however, because high NO_x removal efficiencies for stationary combustion sources may be necessary, based on studies indicating additional adverse health effects of NO_x, atmospheric chemistry studies identifying NO_x as a precursor for other adverse pollutants, the relaxation of NO_x control requirements on mobile sources, and a potential short-term standard which may require greater NO_x control. The aim is to demonstrate flue gas treatment technology for control of NO_x and SO_x/NO_x from stationary combustion sources. The flue gas treatment technology is being considered as add-on technology supplementing combustion modification techniques when high removal efficiencies are required or when the source under consideration is not amenable to extensive control by combustion modification. The overall approach is to conduct strategy and technology assessment activities in parallel with an experimental program progressing from pilot/prototype to full-scale demonstration. Although strategy/assessment studies are incomplete relative to the requirements for flue gas treatment technology, it is planned to proceed with small scale experimental work. Due to its advanced state, Japanese technology is expected to play a major role in planned hardware projects.

SUMMARY

In summary, the Industrial Environmental Research Laboratory at Research Triangle Park is pursuing a very comprehensive environmental engineering program on stationary source combustion control as part of the Interagency Energy/Environmental Program. This program should continue to provide much needed technical data and assessment information for use by concerned organizations in the environmental regulation area, in the industrial user areas, and many others. Figure 16 is a partial listing of primary users of program activities/results.

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° Environmental Engineering R&D Aimed at Technological Trends

- More coal combustion
- Conversion to oil and coal
- Increased use of electrical energy from coal as an alternate to clean fuels
- Increased use of existing capacity
- Increased use of coal in intermediate sized sources (stokers)
- New combustion systems
- New fuels
- Conservation

° Environmental Engineering Methodology Development/Evaluation

- Multi-media environmental assessment (more effective techniques for rapid evaluation using available knowledge)
- Overall environmental evaluation of complex effluents, including comprehensive chemical and biological analysis
- More systematic techniques for control approach evaluation
- Increased emphasis on most effective combined controls for broad spectrum control (control systems)
- Reduced emission levels at the same or reduced cost
- Finding practical candidate options for new comprehensive emission regulatory approaches based on environmental assessment methodology (e.g., minimum acute toxicity effluents)

Figure 1. Environmental engineering R&D challenges in the stationary source combustion area.

An environmental assessment is a continuing iterative study aimed at:

(1) determining the comprehensive multi-media environmental loadings and environmental control costs, from the application of the existing and best future definable sets of control/disposal options to a particular set of sources, processes, or industries; and

(2) comparing the nature of these loadings with existing standards, estimated multi-media environmental goals, and bioassay specifications as a basis for prioritization of problems/control needs and for judgement of environmental effectiveness.

Figure 2. Environmental assessment definition.

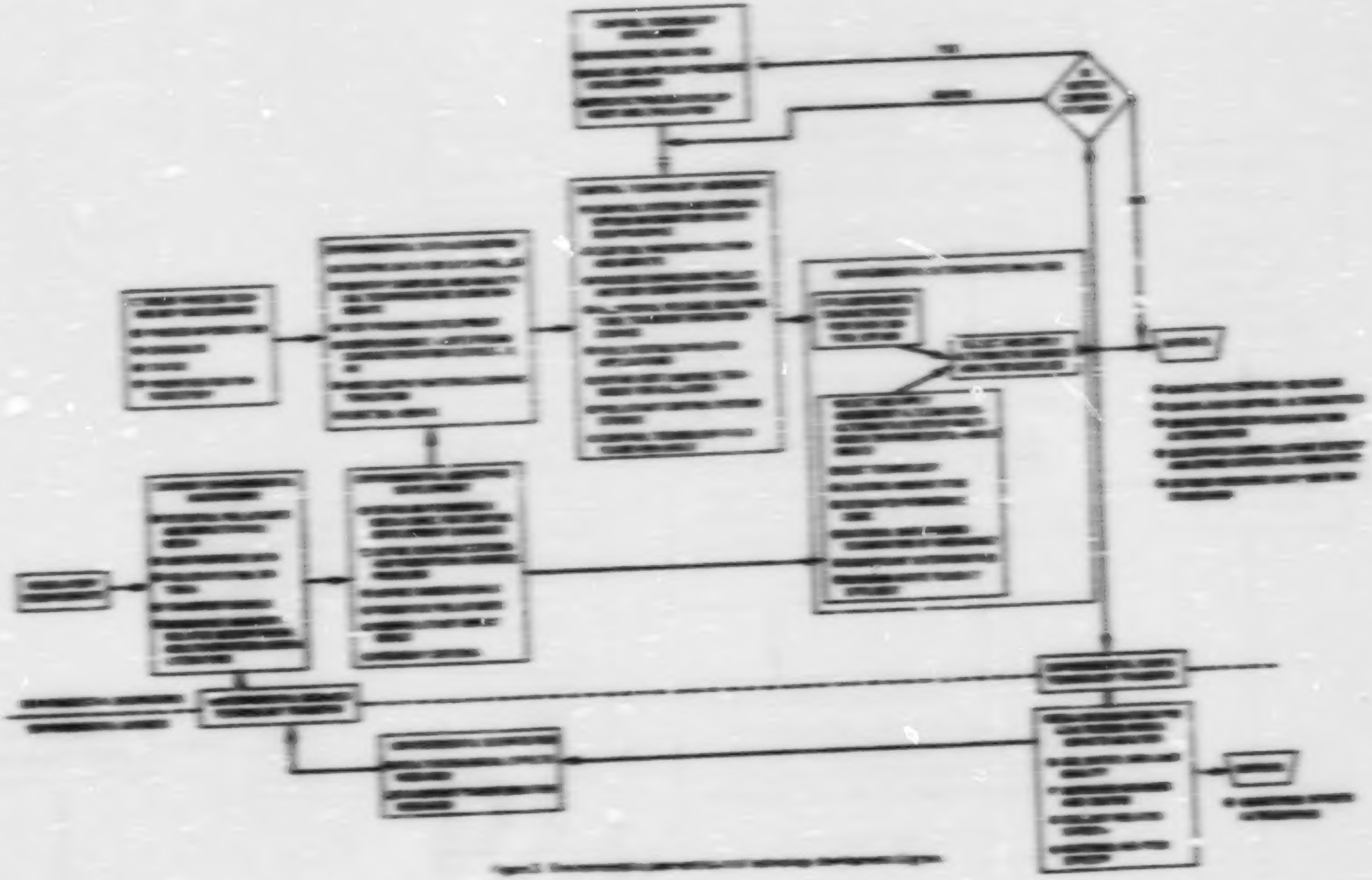
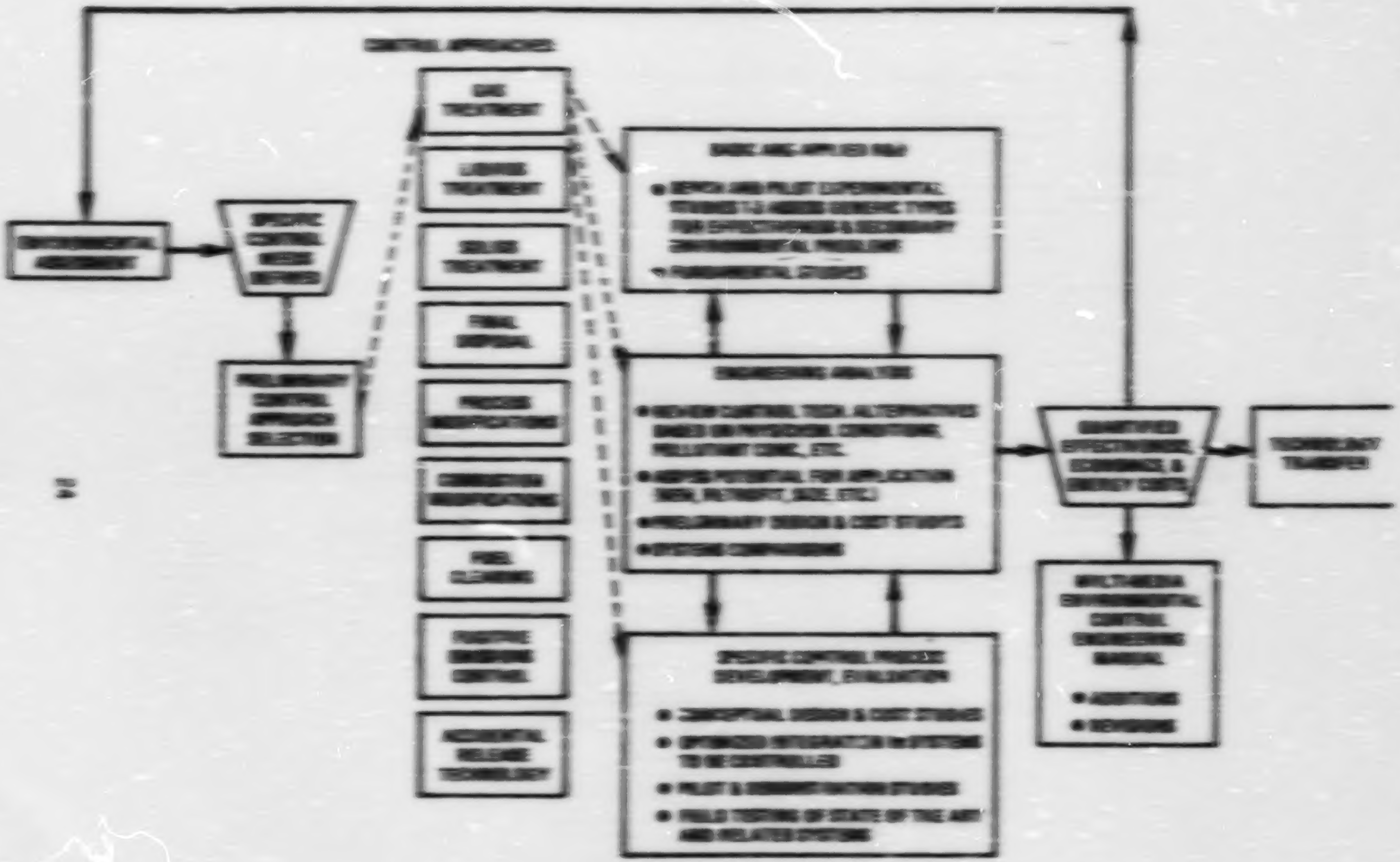


Figure 1. Environmental assessment/control technology development design.


CONTROL APPROACHES
ENVIRONMENTAL ASSESSMENT
SPECIFIC CONTROL NEEDS STUDIES
PRELIMINARY CONTROL APPROACH SELECTION
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ACCIDENTAL RELEASE TECHNOLOGY
BASIC AND APPLIED R&D
● BENCH AND PILOT EXPERIMENTAL STUDIES TO ASSESS GENERIC TYPES FOR EFFECTIVENESS & SECONDARY ENVIRONMENTAL PROBLEMS
● FUNDAMENTAL STUDIES
ENGINEERING ANALYSIS
● REVIEW CONTROL TECH. ALTERNATIVES BASED ON PHYSICOCHEM. CONDITIONS, POLLUTANT CONC., ETC.
● ASSESS POTENTIAL FOR APPLICATION (NEW, RETROFIT, SIZE, ETC.)
● PRELIMINARY DESIGN & COST STUDIES
● SYSTEMS COMPARISONS
SPECIFIC CONTROL PROCESS DEVELOPMENT, EVALUATION
● CONCEPTUAL DESIGN & COST STUDIES
● OPTIMIZED INTEGRATION w/ SYSTEMS TO BE CONTROLLED
● PILOT & DEMONSTRATION STUDIES
● FIELD TESTING OF STATE OF THE ART AND RELATED SYSTEMS
QUANTIFIED EFFECTIVENESS, ECONOMICS, & ENERGY COSTS
TECHNOLOGY TRANSFER
MULTI-MEDIA ENVIRONMENTAL CONTROL ENGINEERING MANUAL
● ADDITIONS
● REVISIONS

Figure 4. Control technology diagram.

Conventional Combustion Systems

- Utility and Industrial Boilers
  - Natural-gas-fired
  - Distillate-fired
  - Resid-fired
  - Coal-fired
- Small Industrial and Commercial Boilers
  - Natural-gas-fired
  - Distillate-fired
  - Resid-fired
  - Coal-fired
- Commercial/Residential Furnaces
  - Natural-gas-fired
  - Distillate-fired
  - Resid-fired
  - Coal-fired
- Industrial Process Furnaces and Afterburners
  - Natural-gas-fired
  - Distillate-fired
  - Resid-fired
  - Coal-fired
- Internal Combustion Engines
  - Natural-gas-fired
  - Distillate-fired
- Gas Turbines
  - Natural-gas-fired
  - Distillate-fired
  - Resid-fired

Advanced Combustion Systems

- Fluid Bed Combustion
  - Resid-fired
  - Coal-fired
  - Coal-reject-fired
- Catalytic Combustion
  - Natural-gas-fired
  - Distillate-fired

Figure 5. Major stationary combustion sources.

- Existing Clean Fuels
- Fuel Cleaning
- Combustion Modifications
- Flue Gas Cleaning

Figure 6. Control program areas.

	Coal 10^{15} kJ/yr	Oil 10^{15} kJ/yr	Gas 10^{15} kJ/yr	Total 10^{15} kJ/yr[a]
Utility Boilers	10.833	3.483	4.906	19.222 (43.5%)
Packaged Boilers[b]	3.449	5.801	6.323[c]	15.573 (35.2%)
Warm Air Furnaces and Miscellaneous Combustion	--	2.132	4.542	6.674 (15.1%)
Gas Turbines	--	0.844	0.681	1.525 (3.4%)
Reciprocating IC Engines	--	0.327[d]	0.913[e]	1.240 (2.8%)
Total	14.282 (32%)	12.587 (29%)	17.365 (39%)	44.234 (100%)

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[a] 1 BTU (British Thermal Unit) = 1.055 kJ (kilojoules)

[b] this sector includes steam and hot water units

[c] includes process gas

[d] includes gasoline and oil portion of dual fuel

[e] includes natural gas portion of dual fuel

Figure 7. 1974 stationary source fuel consumption.(1)

- Existing Clean Fuels
    - Low-sulfur fuel
    - Low-nitrogen fuel
    - Low-ash fuel
    - Low-chlorine fuel
    - Low-trace metal(s) fuel
- Fuel Cleaning
    - Physical cleaning
    - Chemical cleaning
    - Hydrodesulfurization (HDS)
    - Demetallization
    - Hydrodenitrogenation (HDN)
    - Chemically active fluid bed (CAFB)
    - Synthetic fuels
- Combustion Modifications (CM)
    - Low excess air (LEA)
    - Staged combustion (SC)
    - Flue gas recirculation (FGR)
    - Water injection
    - Good operating practice
    - Modified burner
    - Optimum operation and burner/furnace design
    - Fuel additives
    - Furnace reactants (for S, N, Cl)
    - Afterburners
- Gas Treatment (Flue Gas Cleaning)
    - Electrostatic precipitator (ESP)
    - Fabric filter
    - Particulate scrubber
    - Mechanical collectors
    - Granular bed filters
    - Nonregenerable flue gas desulfurization (FGD)
    - Regenerable FGD
    - Flue gas treatment for NO_x
    - Catalytic devices
- Combinations (a few examples for a coal-fired utility boiler)
    - Low-S fuel/CM/baghouse
    - CM/ESP/FGD
    - CM/coal cleaning/FGD
    - CM/coal cleaning/ESP
    - CM/alkali reactant/baghouse

Figure 8. Partial list of control approaches for combustion sources.

Stationary Combustion Source Type	Existing Clean Fuels	Fuel Cleaning	Combustion Modifications	Flue Gas Cleaning
Conventional Combustion Systems				
° Utility and Large Industrial Boilers				
Natural-Gas-Fired	N.A.	No	Yes	Maybe
Distillate-Fired	N.A.	No	Yes	Maybe
Residual-Fired	N.A.	Yes	Yes	Yes
Coal-Fired	Yes	Yes	Yes	Yes
° Small Industrial and Commercial Boilers				
Natural-Gas-Fired	N.A.	No	Yes	Maybe
Distillate-Fired	N.A.	No	Yes	Maybe
Residual-Fired	N.A.	Yes	Yes	Maybe
Coal-Fired	Yes	Yes	Yes	Maybe
° Residential Furnaces				
Natural-Gas-Fired	N.A.	No	Yes	No
Distillate-Fired	N.A.	No	Yes	No
Residual-Fired	N.A.	Yes	Yes	No
Coal-Fired	Yes	Yes	Yes	No
° Industrial Process Furnaces and Afterburners				
Natural-Gas-Fired	N.A.	No	Yes	Maybe
Distillate-Fired	N.A.	No	Yes	Maybe
Residual-Fired	N.A.	Yes	Yes	Maybe
Coal-Fired	Yes	Yes	Yes	Maybe
° I.C. Engines				
Natural-Gas-Fired	N.A.	No	Yes	Maybe
Distillate-Fired	N.A.	No	Yes	Maybe
° Gas Turbines				
Natural-Gas-Fired	N.A.	No	Yes	Maybe
Distillate-Fired	N.A.	No	Yes	Maybe
Residual-Fired	N.A.	Yes	Yes	Maybe
Advanced Combustion Systems				
° Fluidized Bed Combustion				
Residual-Fired	N.A.	Yes	Maybe	Yes
Coal-Fired	Yes	Yes	Maybe	Yes
Coal-Cleaning-Rejects Fired	N.A.	Maybe	Maybe	Yes
° Catalytic Combustion				
Natural-Gas-Fired	N.A.	No	Maybe	No
Distillate-Fired	N.A.	No	Maybe	No

N.A. = Not applicable

Figure 9. Applicability of general control approaches.

Inorganics

- Gaseous Inorganics
  - NO_x
  - SO_x
  - HCl
  - Overall Effluent Acute Toxicity
- Particulate Inorganics
  - Total Inorganic Particulate
  - Primary Sulfates
  - Fine Particulate
  - As
  - V
  - Pb
  - Fe
  - Cr
  - Overall Effluent Acute Toxicity

Organics

- Gaseous Organics and CO
  - Nonmethane HC
  - CO
  - Overall Effluent Acute Toxicity
- Particulate Organics
  - Total Organic Particulate (including carbon)
  - Polycyclic Organic Matter
  - Overall Effluent Acute Toxicity

Figure 10. Overview of some example classes of air pollutants of concern from combustion processes.

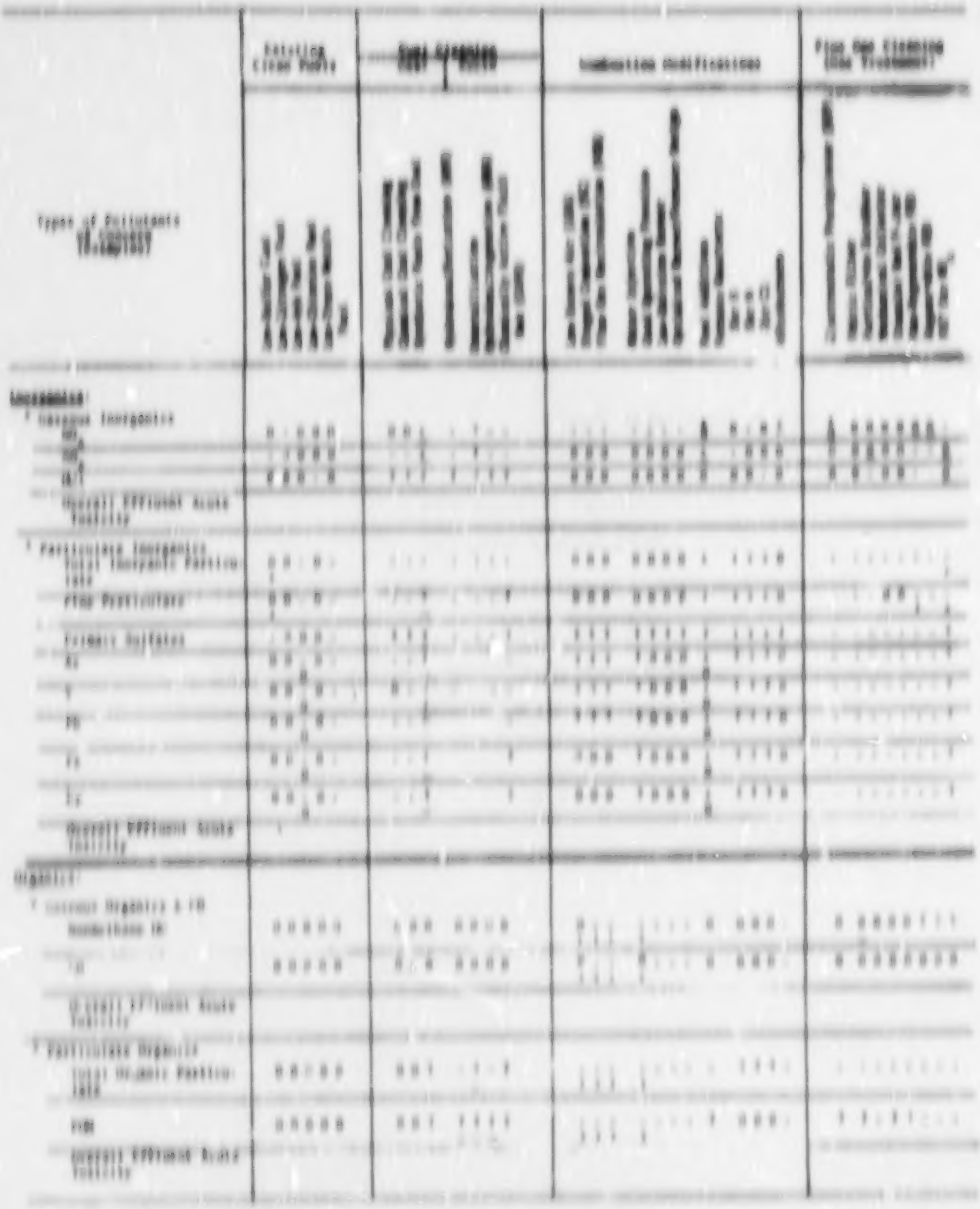
Combustion Modifications
Overall Effluent Acute Toxicity

Figure 11. Relationship of control approaches to the types of pollutants of concern controlled.

° Existing Clean Fuels

  - Environmental Assessment
  - Fuel Contaminant Studies
  - Enhance Useability of Western Low-Sulfur Coals and Lignite
  - Use in Advanced Combustion Systems like Fluidized Bed Combustors

Figure 12. Program activities related to existing clean fuels.

- Fuel Cleaning
  - Coal Cleaning
    - Physical Cleaning
    - Chemical Cleaning
    - Synthetic Fuels
    - Environmental Assessment
    - Control Technology Development for Fuel Processes

  - Residual Oil
    - Development/Application of Chemically Active Fluid Bed (CAFB) as Environmentally Acceptable Approach for Conversion of Gas-Fired Boilers to Residual Oil
    - HDS/HDN/Demetallization
    - Environmental Assessment of Residual Oil Processing/Utilization Alternatives

Figure 15. Program activities relating to fuel cleaning.

- Combustion Modifications Control
  - Environmental Assessment of Combustion Modifications (CM)
  - Applications Testing
  - Development of CM for Utility and Large Industrial Boilers
  - Development of CM for Small Industrial, Commercial and Residential Systems
  - Development of CM for Industrial Process Combustion and Afterburners
  - Development of CM for Stationary Engines
  - Development of CM Based on Advanced Processes
  - Fundamental Combustion Research Studies

Figure 14. Program activities relating to combustion modifications control.

° Flue Gas Cleaning

  - Particulate Control
  - Flue Gas Desulfurization (FGD)
  - Flue Gas Treatment (FGT) for NO_x

Figure 15. Program activities relating to flue gas cleaning.

- EPA
  - IERL-RTP & Cinti (Several inputs to internal program)
  - OEMI/ORD (Inputs for planning, Integrated Assessments, OMB, Congress)
  - Health and Ecological Effects Groups (Samples, source characterization, ecological testing needs, pollutant effects data needs, test facilities)
  - Environmental Sciences (Analytical needs, pollutant transport/transformation study needs, test facilities, samples)
  - Program Offices (Problem definition, definition/develop set of control disposal alternatives and costs for input to standards)
  - Policy and Planning (Development of basis for technology/environmental alternatives and costs)
  - Regional Offices (Information on problems and control options on a multi-media basis; technical assistance)
  - Enforcement (Control information)
- STATE AND LOCAL REGULATORY GROUPS
  - Multi-media integration of industry/environmental considerations
- NIOSH
  - Information
  - Samples
  - Sharing of Data Acquisition Burden
  - Common Control Technology Identification
- ERDA
  - Environmental Input to On-going Program
  - Independent Environmental Review of ERDA's Technology Development
  - Environmental Assessment Methodology
  - Control Technology Recommendations
  - Design Reviews
  - Proposal Reviews
- FEA
  - Energy Related Aspects of Environmental Control Approaches
- NAS
  - Environmental Inputs to National Academy of Sciences/National Academy of Engineering Studies
- ENVIRONMENTAL GROUPS
  - Environmental Alternatives & Control Option Information
- INDUSTRY
  - Process Developers
  - Control Technology Developers/Suppliers
  - Environmental Engineers/Consultants
  - Coal and Oil Processors/Users
  - Equipment Suppliers/Servicers
- GENERAL PUBLIC
  - Guidelines for Direct Use of Individuals
  - Information on Problems/Control

Figure 16. Primary users of program activities/results.

KEYNOTE PAPER

ENVIRONMENTAL ASSESSMENT OF STATIONARY SOURCE NO_x COMBUSTION MODIFICATION TECHNOLOGIES

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ABSTRACT

The EPA has determined that expanded technology for combustion modification NO_x control is needed to maintain air quality for NO_2 in the 1980's and 1990's. In response to the expansion, there is currently a need to (1) ensure that the current and emerging control techniques are environmentally sound, and (2) ensure that the scope and timing of control development is adequate to achieve compliance with current and anticipated air quality standards. The environmental assessment program supports these needs through two main objectives: (1) identify the multimedia environmental impact of stationary combustion sources and NO_x combustion modification controls; and, (2) identify the most cost-effective, environmentally sound NO_x combustion modification controls for attainment and maintenance of current and projected NO_2 air quality standards to the year 2000. The initial effort was a preliminary assessment involving compilation and evaluation of process and impact data and determination of the program approach and priorities. Air quality projections for Los Angeles and Chicago showed that development of advanced combustion modification controls will be needed for all major stationary sources of NO_x. Source priorities for testing and process evaluation were set, in the following order, according to current and projected emissions and prospects for control implementation: utility boilers, watertube industrial boilers, gas turbines, firetube industrial boilers, warm air furnaces, IC engines and industrial process combustion. Data for the economic, operational and incremental environmental impact of combustion modification controls are generally sparse. Incremental emissions of CO, UHC and particulate can be minimized through control development engineering. Other effluents -- POM's, segregating trace metals and sulfates -- show potential for increased emissions due to some combustion modifications. The current effort is focused on field tests and process evaluation to quantify this potential.

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SECTION 1

INTRODUCTION

The 1970 Clean Air Act Amendments designated oxides of nitrogen (NO_x) as one of the criteria pollutants requiring regulatory controls to prevent potential widespread adverse health and welfare effects. Accordingly, in 1971, the EPA set a primary and secondary National Ambient Air Quality Standard (NAAQS) for NO_2 of 100 ug/m^3 (annual average). To attain and maintain the standard, the Clean Air Act mandated control of both mobil and stationary NO_x sources each of which emits approximately half of the nationwide manmade NO_x. Stationary sources are regulated through EPA Standards of Performance for New Stationary Sources which are set as technology becomes available based on the best system of emissions reductions. Additional stationary source standards required to attain air quality in the Air Quality Control Regions can be set for new or existing sources through the State Implementation Plans. Mobile source light duty vehicle emissions were to be reduced by 90 percent to a level of 0.25 g NO_2/km (0.4 g/mile) by 1976.

Since the Clean Air Act, a moderate level of stationary source NO_x control (30- to 60-percent reduction) has been developed and implemented for a variety of source/fuel combinations. EPA standards of performance for new stationary sources were set in 1971 for gas-, oil- and coal- (except lignite) fired large steam generators. A more stringent standard for bituminous coal-fired large steam generators is being considered based on technology developments since 1971 (1). Standards are in preparation for lignite-fired large steam generators, gas turbines, reciprocating internal combustion engines and intermediate size steam generators. Additional local standards have seen set, primarily for new and existing large steam generators and gas turbines, in several NO_x critical areas as part of State Implementation Plans. The net result of this regulatory activity is that there are

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currently over 200 stationary sources controlled to a level of 30- to 50-percent emission reductions. The number of controlled sources is increasing as new units are installed with factory equipped NO_x controls.

A comparable level of emission reduction has been implemented for mobile source light duty vehicles. Although the stationary goal of 90-percent reduction (0.25 g NO_2/km) by 1976 has not been achieved, emission reductions of about 25 percent (1.9 g/km) were in effect for the 1974 to 1976 model years and a 50 percent reduction to 1.25 g/km is currently in effect. Achievement of the 0.25 g/km goal has been deferred indefinitely due to technical difficulties and fuel penalties associated with this level of control (2). Initially, the Energy Supply and Environmental Coordination Act of 1974 deferred compliance to 1978. More recently, the House and Senate versions of the Clean Air Act Amendments of 1977 abolished the 0.25 g/km goal and replaced it with an emission level of 0.62 g/km (1 g/mile) for 1980 and beyond (Senate Bill 252) or 1982 and beyond (House Bill 6161). The EPA Administrator has requested the option of reviving the 0.25 g/km standard in 1983 if shown necessary by studies of the effect of NO_2 on human health (3).

The relaxation of the mobile source emission regulations has placed a greater burden on stationary source NO_x control for maintenance of air quality for NO_2. A number of air quality planning studies have evaluated the stationary source NO_x control requirements in the 1980's and 1990's in view of recent developments (4-7). These studies all conclude that the relaxation of the mobile standards coupled with the continued growth rate of stationary sources will require stationary source controls more stringent than provided for by the current and impending standards of performance for new stationary sources. This conclusion has been reinforced by the recent switch to increased coal use in stationary sources. The studies also conclude that the most cost-effective way to achieve the added stringency is through the use of combustion modification NO_x controls in new sources.

While the above discussion deals with the requirements for stationary source controls to achieve and maintain the current NAAQS (100 $\mu g/m^3$, annual average), there is also the possibility that separate NO_x control requirements will be needed to attain and/or maintain additional NO_2-related standards. Recent data on the health effects of NO_2 suggest that the current NAAQS should be supplemented with a limitation on short-term exposure (7-10), and the House Clean Air Act Amendments (HR 6161) require that the EPA consider setting a short-term NO_2 standard. EPA plans to consider the need for a short-term standard in 1978 when the NO_2 air quality criteria document (11) is updated (12,13).

For the longer term, EPA is continuing to evaluate the need for additional NO_x regulation as part of the oxidant control strategy or for control of pollutants for which NO_x is a precursor, e.g., nitrates and nitrosamines (7,8,12-15). These regulations could be in the form of source emission controls or additional ambient air quality standards. In either case, additional stationary source control technology could be required to comply with the standards.

In summary, the developments in NO_x regulatory control since the Clean Air Act are leading, in the near term, to fairly extensive implementation of moderate levels of control through hardware modification to existing units or new units of conventional design. For the far term, air quality projections show the need for levels of control more advanced than originally anticipated. Control of new sources through low-NO_x redesigns is the preferred approach to achieving these advanced levels of control. This expanding use of combustion modifications highlights the need for an environmental assessment program which is the subject of this paper.

SECTION 2

NO_x E/A PROGRAM OVERVIEW

With the increasing use of conventional combustion modification techniques and the prospect of development and use of advanced techniques, control developers and users need to know the environmental, economic, energy and engineering implications of combustion modification technology. This information is needed to aid in selection of control systems, to support the setting of standards and to guide control R&D programs. The "Environmental Assessment of Stationary Source NO_x Combustion Modification Technologies" (NO_x E/A) was initiated in June 1975 to provide this information. Specifically, the program addresses two questions:

- What are the impacts, and potential corrective measures, associated with the use of specific existing and advanced combustion modification techniques, e.g.
  - The change in gaseous, liquid and solid emissions to the air, water and land due to NO_x controls
  - The capital and operating cost of NO_x controls per unit reduction in NO_x
  - The change in energy consumption efficiency
  - The change in equipment operating performance
- What are the priorities and schedule for NO_x control technology development considering:
  - The above impacts for each source/control combination
  - Control requirements to attain and maintain the current annual average NO_2 ambient air quality standard

- Control requirements to attain and maintain a potential short-term NO_2 standard, or, other NO_x related standard (oxidants)
- Alternate mobile source standards
- Alternate energy and equipment use scenarios to the year 2000 in the Air Quality Control Regions with potential NO_x problems

The NO_x E/A program has a major task to address each of these questions. The "Process Engineering and Environmental Assessment" task quantifies impacts from specific combinations of stationary combustion sources and NO_x controls ranging from the use of existing control technology on conventional equipment to the use of developing control techniques on advanced equipment design. The process engineering component of this task is evaluating the hardware modifications required for NO_x control and quantifying the accompanying cost and impact on fuel consumption and system operation. This effort is drawing on the results of past and ongoing field demonstration tests of NO_x controls. The environmental assessment component of the task quantifies the near-source impacts on human health as well as terrestrial and aquatic ecology from the change in gaseous, liquid and solid emissions resulting from the use of NO_x controls. The results of the task are rankings of source/control combinations, now and in the future, based on the potential impacts associated with the use of NO_x combustion modification techniques.

The second major task, "Systems Analysis," evaluates the priorities and required schedule for NO_x control development based on current and projected control requirements on a regional and national basis. This task uses air quality projection models for several NO_x critical regions. These models together with the source-specific impact data from the process engineering task, suggest the most cost-effective and environmentally sound mix of stationary control techniques for given constraints on source growth, ambient air quality goals and mobile source standards. Several scenarios for energy use and mobile source standards between now and the year 2000 are being used so that the impact of these contingencies on control needs can be evaluated. The results of this task are used within the NO_x E/A to set program priorities. They are also intended to assist the EPA in control R&D planning.

The two major tasks cited above are supported by three other tasks, "Emission Characterization," "Impacts and Standards," and "Experimental Testing." The relationship and scope of these tasks are shown on Figure 1. Here, the rectangular boxes denote subtasks and the ovals show program output. The initial effort, shown at the top of the figure, developed the approaches, supporting data and priorities on sources, controls pollutants and impacts for the assessments and system analyses currently in progress. These initial results were documented in detail in a preliminary environmental assessment report (16), the final of which will be available in September. The remainder of this paper summarizes the results of the preliminary assessment with emphasis on those areas most relevant to this symposium.

SECTION 3

SOURCES OF NO_x EMISSIONS

The major sources of oxides of nitrogen emitted to the atmosphere are shown on Figure 2. The stationary fuel combustion sources being assessed in the NO_x E/A are bracketed at the top of the figure. On a global basis, it is estimated that up to 90 percent of NO_x mass emissions are from the natural processes of biological decay and lightning (17). In urban industrial areas, however, the reverse is true. There, manmade sources account for up to 90 percent of ambient NO_2 concentrations.

Manmade NO_x emissions in the United States in 1974 were 21.1×10^6 metric tonnes (23×10^6 tons) on an NO_2 basis. Of this amount, 9.6×10^6 MT (10.6×10^6 tons), or 46 percent were due to mobile sources consisting of light and heavy duty highway vehicles, aircraft, trains, ships and off-road vehicles such as construction equipment (18). The remaining 54 percent of manmade NO_x emissions are due to stationary sources distributed by sector, as shown in Figure 3. The four largest sectors are utility and industrial boilers, IC engines, and residential and commercial warm air furnaces. The "other" category is fugitive emissions, largely open burning. Combustion sources account for over 98 percent of stationary emissions with conventional fossil fuel combustion responsible for 94 percent.

The emission inventory in Figure 3 includes estimates of the effect of utility boiler NO_x controls on nationwide emissions. These estimates show that the controlled nationwide utility boiler emissions are only 3 percent below uncontrolled levels for 1974. Although there are a number of gas turbines with NO_x controls, the effect of these controls on a nationwide emission estimate was negligible in 1974. Thus, the current impact of NO_x regulations on nationwide emissions is small. The extent of control implementation is increasing, however, particularly as new sources covered by emission standards are installed.

The distribution of stationary emissions by fuel is shown on Table I. Coal-fired equipment generated nearly 37 percent of stationary NO_x but consumed only 32 percent of fuel energy used in stationary sources. By contrast, natural gas-fired sources consumed 40 percent of stationary fuel energy but emitted only 32 percent of stationary source NO_x. This contrast is largely due to the higher NO_x-forming potential of coal due to high concentration of bound nitrogen in the fuel. This effect of fuel type on NO_x emissions is of particular relevance with the increase in use of potentially high NO_x fuels — coal and heavy oil — as a result of the clean fuels supply deficit.

An emission inventory of stationary combustion NO_x sources was also generated for other pollutants for which emission data were available. The results for the criteria pollutants, sulfates and polcyclic organic matter (POM) are summarized on Table II. The inventory for trace metals is given in Reference 16. The emission factor data for the criteria pollutants was generally of good quality. As expected, the emissions of hydrocarbons and CO from the major stationary NO_x sources (except IC engines) are small compared to mobile sources. Also, the only significant source, on a mass emission basis, of combustion generated SO_x and particulate is boilers firing coal or heavy oil. One exception is the process heating sector (cement kilns, etc.) where the emissions are largely process generated rather than combustion generated as in the other sectors. The emission factor data for noncriteria pollutants was generally sparse and of low quality. For example, little data is available for individual species of POMs, and the data for the total POMs as shown in Table II exhibits a scatter of over two orders of magnitude. Similarly for trace metals, data are available only for elemental loading rather than for metallic species. The limited elemental data available show a high dependence on fuel composition.

The source sector groupings shown in Figure 2 and Table I consist of a variety of equipment design/fuel combinations, many of which may have significantly different potential for NO_x emissions and/or NO_x control. The emission inventory cited herein considered nearly 100 such combinations. However, the ranking of the most significant of the combinations, given in Table III, shows that the top 30 emitters account for over 90 percent of stationary NO_x emissions. NO_x control technology can thus be leveraged considerably by treating the major emitters in depth and using this basic technology for spinoffs to the minor sources.

The NO_x E/A emission inventory summarized in Figure 3 and Tables I to III is being updated and revised as new field test data, particularly for noncriteria trace pollutants, become available. The inventory is used in the NO_x E/A in two ways. First, the total mass emissions for a given source and pollutant are used to set preliminary relative priorities among the source/fuel combinations. Second, the emission factor data in the inventory are used as input to the impact assessment calculation. Maximum ground level concentrations of pollutants are estimated by approximating the dispersion and, if relevant, the transformation of the flue gas pollutant concentration. These ground level concentrations are then compared to impact threshold levels where the concentration of pollutants may be potentially harmful to human health or the ecology. This procedure highlights potential source/pollutant problems requiring attention in the assessments and field testing.

SECTION 4

EVALUATION OF COMBUSTION MODIFICATION TECHNOLOGY

The regulatory program to control emissions from the sources discussed above emphasizes application of best available control technology in new units. New source controls are emphasized since experience has shown them to be more effective, less costly, and less disruptive than retrofit control of existing equipment. The current and impending Standards of Performance for New Stationary Sources applicable to NO_x control for combustion sources are summarized in Table IV. EPA's Office of Air Quality Planning and Standards anticipates additions to the standards shown on Table IV (6,19). These additions may involve both the inclusion of sources not presently regulated and the setting of more stringent standards for sources under current or impending controls. This trend is true also for state and local standards on new and existing equipment.

The stationary source NO_x emission standards set to date and those envisioned for the near future are based on the use of combustion modification techniques. This is because the rate of formation of NO_x is dominated by combustion conditions and is accordingly cost-effectively controlled by modifications to the combustion process. Both thermal NO_x — formed from the oxidation of nitrogen in the combustion air — and fuel NO_x — formed from oxidation of bound nitrogen in the fuel — are strongly affected by the local availability of oxygen in the primary fuel/air mixing zone. Additionally, thermal NO_x is extremely sensitive to the local flame temperature. The modified combustion conditions which have been shown to suppress NO_x emissions are:

- Decreased primary flame zone O_2 level
- Decreased time of exposure at high temperatures
- Chemical reduction of NO_x in the post-flame region

Table V indicates several concepts for achieving these modified combustion conditions and relates these concepts to actual hardware modifications for the major equipment categories. The controls listed for decreased O_2 are also generally effective for peak flame temperature reduction but are not repeated. The applicable controls are categorized according to their relevance to current and near-term application of operational adjustments or hardware modifications on existing units or new units of conventional design. The table also lists techniques for far-term application to major redesign of new sources. Generally, there is more latitude in control selection for thermal NO_x than for fuel NO_x. All control concepts listed are effective for thermal NO_x reduction, but those that act mainly to decrease peak flame temperatures are relatively ineffective for fuel NO_x. With the firing of coal and heavy oil, simultaneous suppression of thermal and fuel NO_x is desired. Here, the preferred control techniques are those that reduce O_2 in the primary flame zone: low excess air, burner modifications and off-stoichiometric combustion (biased burner firing, burners out of service, overfire air).

In the NO_x E/A, the applicable equipment/control combinations indicated on Figure 5 were preliminarily evaluated on the basis of data and operational experience from field demonstrations. This evaluation was done both to obtain an initial data base to conduct the process engineering studies and to set program priorities for the assessment of source/control combinations. The results of the evaluation are summarized in Table VI. These results, particularly the achievable emission level, the estimated cost and the operational impact, are currently being evaluated in detail in the process engineering task.

In Table VI, the current technology column refers to control techniques which are at least in the field demonstration stage. In some cases, the current technology itself is continuing to be refined by field tests. Emerging technology refers to techniques which are still under development as well as to those which are not currently used due to lack of regulatory requirement. The most extensive application of combustion modification technology has been to the control of new and existing utility boilers. For gas- and oil-fired units, the vast majority of controls are retrofits to existing units since few new units of this type are being sold. For coal-fired units, most control applications are for new units to achieve compliance with the Standards of Performance for New Stationary Sources.

Low excess air (LEA) firing is the most widely used technique for control of both thermal and fuel NO_x. LEA is also effective for increasing unit thermal efficiency. Its use is limited by the increase in smoke or CO emissions which occur at low levels of excess air. Low excess air firing is typically the first technique implemented as part of a control program and is normally included when other techniques are used. Its use requires minimal operational modification involving closer supervision by plant personnel, or in some cases, installation of more sophisticated automatic control systems.

Off-stoichiometric combustion through use of biased firing, or burners out of service (on existing units) and overfire air ports (on new units) is a very effective technique for control of both thermal NO_x and fuel NO_x. NO_x reduction in the range of 30 to 50 percent has been demonstrated for both oil-fired boilers (20) and coal-fired boilers (21-23). Three of the major boiler manufacturers are incorporating staged combustion in new unit designs as the means of complying with the 0.7 lb $NO_2/10^6$ Btu standard of performance for new stationary sources. Emission reductions achievable with staging are limited by operational problems such as CO or soot emissions and convective section fouling, which may arise at high levels of staging. Additionally, there is concern that operation of the primary flame zone at fuel-rich conditions can accelerate watertube corrosion rates (21).

Advanced burner design is an alternate method for thermal and fuel NO_x reduction through controlled mixing of fuel and air. Recent tests with a new dual register coal burner (25) showed a 35-percent NO_x reduction relative to conventional burners. A 50-percent reduction resulted when the dual register burners were fired with staged combustion.

Flue gas recirculation (FGR) has been implemented to a limited extent for control of thermal NO_x with the firing of natural gas and oil. FGR does not appear to be as effective for control of fuel NO_x emissions, however. Recent tests with a coal-fired boiler showed only a 13- to 17-percent NO_x reduction at 15-percent FGR (23). Thermal NO_x reductions achievable by FGR are limited, on some units, by the occurrence of flame instability and boiler rumble at high levels of recirculated flue gas.

Current developmental activity in the utility boiler area involves (1) studies of boiler performance and potential operational problems under conditions of extensive control (14, 26); (2) development and application of new burner designs (27) and development of advanced staged combustion techniques (28); and (3) evaluation of NO_x controls with alternate fuels and with the firing of mixed fuels (29).

NO_x control application is currently very limited in industrial boilers. Their use is expected to increase, however, in view of impending local standards for existing units in some areas, and the planned NSPS for new units. Control technology is in the demonstration stage. Overfire air and flue gas recirculation have been applied to gas- and oil-fired firetube and watertube commercial and industrial boilers (30, 31). NO_x reductions of 30 to 40 percent were typically achieved. The results were mixed, however, showing that the effectiveness of OFA and FGR in industrial boilers is very dependent on equipment design and fuel. Meanwhile, advanced low-NO_x burner development is underway by the EPA (32) and in the private sector. In the long run, this may prove a more attractive approach than external combustion modifications due to the wide diversity of commercial and industrial boiler designs. Stoker-fired industrial boilers are being tested in the field to determine the feasibility for western coal firing (33) and their NO_x emission characteristics (34).

NO_x controls for stationary gas turbines have been implemented as part of state and local pollution control regulations. Additionally, an NSPS of 75 ppm at 15-percent O_2 is impending. Current practice is to use water injection into the primary flame zone to reduce the flame temperature and suppress NO_x (35). This approach can reduce operational efficiency and may not be as attractive in the long term as dry controls centering on advanced combustor can design. The incremental annualized operating cost for water injection systems on industrial utility gas turbines is 0.4 to 1.5 mils per kWh. This cost is equivalent to about a 2-percent increase in operating costs. Emerging technology for gas turbines is focused on combustor can redesign. Candidate concepts include premixing, prevaporization and can aerodynamic optimization (36).

Control development for residential warm air furnaces has centered on burner modifications matched to the firebox aerodynamics and heat transfer characteristics. A prototype residential system (37) using an optimized burner/firebox combination was able to achieve a 65-percent reduction in NO_x emissions relative to conventional systems while increasing the fuel consumption efficiency by up to 10 percent. Long-term field validation tests are planned for the prototype unit (38).

There is very limited field implementation of NO_x controls for reciprocating IC engines. Lab demonstrations have shown that 20- to 40-percent emission reduction is achievable with a combination of spark or injector retard, leanout of air-fuel ratio, reduced manifold air temperature and derating (39). A consumption penalty of 2 to 8 percent is associated with these controls, however. Use of catalytic converters and exhaust gas recirculation based on mobile source technology is still under development. In the far term, NO_x control by combustion chamber redesign appears to be the most attractive approach. The EPA is planning a developmental program to pursue this.

A field test program is underway to identify emission characteristics and control options for industrial process furnaces and heaters (40). Initial results of tests with minor operational modifications show that the NO_x control potential for industrial process equipment may be limited by the constraints on the combustion conditions imposed by the process requirements. Future tests will evaluate major equipment modifications on approximately five industrial process equipment types.

The results of the control development efforts summarized above are being used in the NO_x E/A to develop and standardize a control process data base and to update projections of availability of advanced technology. The remainder of this paper discusses priorities being used in this effort.

SECTION 5

PRELIMINARY BASELINE AND CONTROLLED IMPACT EVALUATION

Assessment of potential adverse pollutant impacts from baseline, uncontrolled operation and operation with NO_x controls is a key objective of the NOx E/A. During the initial stage of the program, a preliminary screening of potential impacts was made to assist in setting priorities in the experimental testing and analysis and in guiding the subsequent, more detailed, impact assessment.

The baseline impact screening was done in three steps:

- Compilation of emission data for criteria pollutants, sulfate, trace metals and classes of vapor phase hydrocarbons and polycyclic organic matter
- Estimation of maximum pollutant ground level concentration by a dispersion approximation considering average stack height and unit capacity (point sources) and average source density (area sources)
- Comparison of pollutant ground level concentration to estimates of threshold pollutant levels for potential hazard to human health via inhalation

For each major source/fuel combination, three groups of pollutants were identified: those below 10 percent of the threshold level; those between 10 percent and 100 percent of the threshold level; and those that exceed the threshold level. The results for the last two groups are summarized in Table VII. It is stressed that the analysis used in Table VII was for screening purposes only and that a listing of a pollutant in the table does not imply that a quantifiable adverse impact exists. More data of better quality for emissions and impact criteria are required together with a more detailed dispersion calculation to quantify impacts. It is also noted, however, that there are numerous potential pollutants for which the emission data were too sparse to include in the screening analysis. Thus, the availability of more emissions data in the future could add new pollutants to the list as well as remove some of those presently listed.

For operation with NO_x controls, the three-step screening approach described above was practical only for the criteria pollutants due to a lack of data for other trace pollutants. Here, the screening analysis consisted of a qualitative estimate of the potential of a given combustion modification technique for increasing the emissions of a class of pollutants. This was done by relating the change in combustion conditions due to control, e.g., residence time, local temperature, stoichiometry, and the formative mechanism of the pollutant class. The potential for increased emissions was divided into three levels:

- High potential, where the emissions data unambiguously show that applying the NO_x control results in significantly increased emissions of a specific pollutant
- Medium potential, where preliminary screening of formative mechanisms indicates that NO_x control could conceivably cause increased pollutant emissions, but confirming data are lacking, contradictory or inconclusive
- Low potential, where the emissions data clearly show that specific pollutant emission levels decrease when the NO_x control is applied, or where the preliminary screening definitely indicates a similar conclusion, even though data are lacking

The results of the screening evaluation for boilers firing coal or heavy oil are summarized in Table VIII. Similar results were generated for reciprocating IC engines and gas turbines which are documented in Reference 15.

It is emphasized that a designation of "high potential" does not necessarily indicate that the pollutant impact is significant, but only that the emission rate is thought to increase due to the use of NO_x controls.

Better data are needed to determine if the incremental impact due to NO_x controls is significant compared to the baseline impact.

As Table VII illustrates, applying preferred NO_x combustion controls to boilers should have few adverse effects on incremental emissions of CO, vapor phase hydrocarbons or particulates. It is true that indiscriminantly lowering excess air can have drastic effects in boiler CO emissions, and that particulate emissions can increase with staged combustion and flue gas recirculation. However, with suitable engineering during development and implementation of these modifications, adverse incremental emissions problems can be minimized. In contrast, residual emissions of sulfate, organics, and trace metals show medium to high potential for increases in applying almost every combustion control. For trace metal and organic emissions, substantiating data are largely lacking, but fundamental formation mechanisms give cause for justifiable concern. In the case of sulfate emissions, fundamental formation mechanisms suggest that these emissions should remain unchanged or decrease with all controls except ammonia injection. However, complex interactive effects are difficult to elucidate, and this pollutant class is sufficiently hazardous to justify expressing some concern in the present absence of conclusive data.

The preliminary impact evaluation suggests that with baseline operation, the emissions of some pollutants may approach a threshold level of potential hazard. Also, combustion modifications show potential for increasing the emissions of some pollutants. More data are needed to determine if these effects have a significant environmental impact and to suggest corrective action if needed. The value of this preliminary evaluation is in guiding the gathering of more data so that the environmental impacts can be better quantified.

SECTION 6

EVALUATION OF NO_x CONTROL REQUIREMENTS

The extent to which combustion modification controls are needed in the future is crucial in setting priorities within the NO_x E/A as well as in guiding control R&D. To estimate this extent, a preliminary analysis was made to identify the type and level of stationary source NO_x controls to attain the National Ambient Air Quality Standard for NO_2. Since this preliminary analysis was intended primarily for screening program priorities, a simple air quality model (rollback) was used. Although this model has been used in most prior NO_x strategy studies, it is limited in accuracy and flexibility and will be supplemented with more complex models later in the program when more definitive estimates of control requirements are generated.

Control requirements were examined for the years 1985 and 2000 for two Air Quality Control Regions — Los Angeles and Chicago — and for a variety of growth scenarios and mobile source control strategies. Los Angeles and Chicago were selected because they have the highest ambient NO_x levels in the U.S. Furthermore, these two areas have distinctly different sources of NO_x. Mobile sources account for 60 percent of the NO_x emissions in Los Angeles but only 30 percent in Chicago. Coal-fired power plants and industrial sources account for 45 percent of the NO_x emissions in Chicago, whereas no coal is burned in Los Angeles. Therefore, analysis of these two areas gives a good composite of the controls which should be developed to meet current air quality goals anywhere in the nation.

Two growth scenarios for stationary sources were considered — one — a high growth case — representing a continuation of historical trends and the other — a low growth case — to consider moderate energy conservation and rising energy costs. Two mobile growth scenarios were also considered: a historical growth case (3.5 percent/year) with NO_x emission regulations of 0.62 g/Km (1 g/mile); and a low growth case (1 percent/year) with NO_x regulations of 0.25 g/Km (0.4 g/mile) beyond 1981.

The modified rollback model was used to relate changes in NO_x emissions from mobile or stationary sources to changes in the maximum annual average NO_2 ambient concentration. The form of the rollback model used allowed the emissions from each category (mobile, power plants, residences, etc.) to be separately weighted to account for dispersion effects such as stack height.

For each AQCR and each mobile/stationary scenario, a succession of stationary control was added to the modified rollback model until the air quality standard was achieved. The order of selection of stationary controls was based on control cost per unit reduction in ambient NO_2 concentration. The data for this selection were generated in the preliminary evaluation of NO_x controls discussed in Section 4. Control costs were estimated both for existing technology and for technology projected to be available in 1985 and 2000.

The results show that, to 1985, nearly all available combustion modification techniques will be needed to attain and maintain air quality for the two regions. Beyond 1985, all advanced combustion modification, including ammonia injection, will be needed for all cases considered except the low mobile growth case in Los Angeles. The implications of these results are that (1) all current and advanced NO_x controls will need to be considered in the NO_x E/A; and (2) expanded development of advanced combustion modification controls will be needed to assure that air quality goals are met.

The above analysis is currently being refined through use of a photochemical reactive air quality model to consider:

- Additional AQCR's
- Secondary pollutants (oxidant-hydrocarbon-NO_x reactions)
- Alternate NO_2 related standards (short term NO_2, oxidants)
- Source stack height and source density effects.

These refinements, together with revised data on control effectiveness and cost will be used throughout the remainder of the program to update the estimated control requirements.

SECTION 7

NO_x ENVIRONMENTAL ASSESSMENT PRIORITIES

The final step in the initial NO_x E/A effort was the setting of priorities among the numerous combinations of combustion sources and combustion modification techniques. These priorities are used within the programs to set the schedule and level of effort for the detailed process engineering studies and the field testing. The prioritization was done to focus the early effort on those sources and controls which are most important in near term regulatory control programs. Minor sources and far term controls will be considered in the third year.

The prioritization was done in two steps. First the major source/fuel combinations were ranked according to:

- Extent of current or impending NO_x regulations for the source category
- Ranking of source NO_x emissions on a national basis
- Relative potential for adverse environmental impacts
- Current and projected effectiveness of the source in urban NO_x abatement

The ranking for each of these criteria and the overall ranking is shown on Table IX. The equipment design types within a source category are divided into "major" and "minor" categories. Major refers to conventional designs likely to be controlled for NO_x. These design types will be given primary emphasis in the process studies and are candidates for field tests. Minor refers to those design types which are obsolete or otherwise unlikely to see extensive NO_x control implementation in the near term. These design types will be given secondary emphasis in the process studies and will generally not be candidates for field tests.

The source prioritization discussed above is extended on Table X to include consideration of specific source/control combinations. The table shows which source/control combinations are to receive major or minor emphasis in the process studies of near-term applications. The table also shows preliminary selection of which advanced source/control combinations will be evaluated in the later study of far-term applications. The prioritization of current technology considered the extent of current applications of specific source/control combinations and the cost effectiveness of a given control compared to competitive techniques. Major emphasis will be given to the vast majority of source/control combinations likely to see significant control in the next 5 years. The selection of advanced techniques for study in the far-term effort was based on the developmental status and schedule as well as the potential availability of competitive techniques. The selection of advanced techniques also considered the results of the preliminary evaluation of control requirements which showed the need for advanced combustion modifications and, possibly, ammonia injection in the 1980's and 1990's. Advanced techniques which are being covered by other assessments efforts (e.g., fluidized beds, advanced cycles) will be given minor emphasis in the far-term effort.

The NO_x E/A priorities are currently being used to guide three major efforts shown in Figure 1:

- Conduct field tests for baseline and controlled multimedia emissions
- Generate control technology process studies (control effectiveness, cost and operational impact) for the major sources
- Select, adapt and apply photochemical air quality model to the estimation of control requirements

As these results become available, they are being combined with the results of the supporting tasks on emission characterization and impacts and standards to generate the environmental assessments of control techniques.

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TABLE I. SUMMARY OF 1974 STATIONARY SOURCE NO_x EMISSIONS BY FUEL — 1,000 Mg (PERCENT OF TOTAL)

Sector	Coal	Oil	Gas	Total
Utility Boilers	3,564 (31.0)	848 (7.4)	1156 (10.1)	5568 (48.5)
Packaged Boilers[a]	679.7 (5.9)	886 (7.7)	779 (6.8)	2344.7 (20.4)
Warm Air Furnaces		129 (1.1)	190 (1.6)	320 (2.8)
Gas Turbines		216 (1.9)	120 (1.0)	336 (2.9)
Reciprocating IC Engines	—	456[b] (3.9)	1400 (12.2)	1856 (16.2)
Industrial Process Heating	—	—	—	333 (2.9)
Noncombustion	—	—	—	193 (1.7)
Incineration	—	—	—	40 (0.34)
Fugitive	—	—	—	498 (4.3)
Total	4,243.7 (37.0)	2,535 (22.1)	3,645 (31.7)	11,478

[a] Includes steam and hot water commercial and residential heating units

[b] Includes gasoline

TABLE 11. 1974 SUMMARY OF AIR AND SOLID POLLUTANT EMISSION FROM STATIONARY FUEL BURNING EQUIPMENT (1,000 Mg)

	NO_x[b]	SO_x	HC	CO	Part.	Sulfates	POM	Dry Ash Removal	Sluiced Ash Removal
Utility Boilers	5,553	16,700	29.5	270	5,065	231	0.05 – 1.2	6.78	24.78
Packaged Boilers	2,346	6,420	72.1	175	5,221	146	0.2 – 67.8	4.40	1.87
Warm Air Furnaces & Misc. Comb.	321	232	29.7	132.6	39.3	6.4	0.06	—	—
Gas Turbines	338	18.5	13.7	73.4	17.3	a	a	—	—
Recip. IC Engines	1,857	19.6	578	1,804	21.5	a	a	—	—
Process Heating	333	602	186	9,379	4,857	a	a	—	—
TOTAL	10,747	24,122	889	11,659	16,125	382	69	—	—

[a] No emission factor available

[b] Controlled NO_x

[c] Based on 80 percent bottom and flyash removal by sluicing methods; 20 percent dry sulfur removal

TABLE III. NO_x MASS EMISSION RANKING OF STATIONARY COMBUSTION EQUIPMENT AND CRITERIA POLLUTANT AND FUEL USE CROSS RANKING

Sector	Equipment Type	Fuel	Annual NO_x Emissions (Mg)	Cumulative (Mg)	Cumulative Percent	Fuel Rank	SO_x Rank	CO Rank	HC Rank	Part. Rank
1 Utility Boilers	Tangential	Coal	1,410,000	1,410,000	13.1	1	1	7	16	2
2 Reciprocating IC Engines	>75 kW/cyl	Gas	1,202,000	2,612,000	24.8	27	>30	4	1	>30
3 Utility Boilers	Wall Firing	Coal	946,000	3,558,000	32.5	3	2	6	23	5
4 Utility Boilers	Cyclone Furnace	Coal	863,500	4,421,500	41.5	6	3	12	9	13
5 Utility Boilers	Wall Firing	Gas	758,200	5,179,000	48.4	4	>30	13	28	>30
6 Utility Boilers	Wall Firing	Oil	481,000	5,660,000	52.8	8	9	17	27	18
7 Utility Boilers	Horizontally Opposed	Gas	378,700	6,039,500	56.3	14	>30	24	>25	>30
8 Reciprocating IC Engines	75 kW/hr – 75 kW/cyl	Oil	335,000	6,374,500	59.4	>30	>30	3	3	25
9 Packaged Boilers	Watertube >29 MW	Gas	330,500	6,705,000	62.3	16	>30	20	19	>30
10 Packaged Boilers	Watertube Stoker <29 MW	Coal	292,770	7,000,770	64.9	7	4	11	4	1
11 Utility Boilers	Horizontally Opposed	Coal	270,800	7,271,570	67.6	23	5	>30	>30	7
12 Packaged Boilers	Watertube <29 MW	Oil	222,400	7,494,000	69.5	26	16	>30	26	22
13 Utility Boilers	Tangential	Oil	208,000	7,702,400	71.5	12	10	21	>30	15
14 Packaged Boilers	Firetube Scotch	Oil	203,000	7,905,400	73.4	11	11	>30	>30	16
15 Packaged Boilers	Watertube >29 MW	Gas	188,000	8,093,400	75.2	5	>30	>30	22	>30
16 Utility Boilers	Horizontally Opposed	Oil	177,000	8,270,400	76.7	>30	17	>30	>30	27
17 Packaged Boilers	Watertube >29 MW	Coal	154,220	8,424,620	78.2	>30	8	>30	>25	9
18 Industrial Process Comb.	Forced & Natural Draft Refinery Heaters	Oil	147,200	8,571,820	79.6	>30	29	>30	19	21
19 Utility Boilers	Tangential	Gas	146,000	8,717,820	80.9	13	>30	>30	>30	>30
20 Packaged Boilers	Firetube Firebox	Oil	139,220	8,857,040	82.2	17	12	>30	>30	20

TABLE III. Concluded

Sector	Equipment Type	Fuel	Annual NO_x Emissions (Mg)	Cumulative (Mg)	Cumulative Percent	Fuel Rank	SO_x Rank	CO Rank	HC Rank	Part. Rank
21 Packaged Boilers	Watertube Stoker	Coal	125,300	8,996,520	83.4	>30	7	39	29	6
22 Gas Turbines	13.5 – 59 GJ/hr	Oil	118,500	9,115,020	84.5	30	>30	15	14	>30
23 Packaged Boilers	Watertube <105 GJ/hr	Oil	116,400	9,231,487	85.6	27	15	>30	>30	22
24 Warm Air Furnaces	Central	Gas	106,300	9,337,750	86.5	2	>30	13	8	25
25 Packaged Boilers	Firetube Stoker <105 GJ/hr	Coal	102,040	9,439,790	87.5	29	6	>30	13	6
26 Packaged Boilers	Firetube Scotch	Gas	98,011	9,537,800	88.4	19	>30	>30	>30	>30
27 Gas Turbines	>59 GJ/hr	Oil	97,400	9,635,200	89.3	>30	>30	>30	30	>30
28 Reciprocating IC Engines	<370 MJ/hr/cyl	Oil	94,000	9,729,200	90.2	>30	>30	22	13	>30
29 Industrial Process Comb.	Forced & Natural Draft Refinery Heaters	Gas	92,600	9,821,800	91.0	15	<23	>30	7	30
30 Utility Boilers	Vertical and Stoker	Coal	90,900	9,912,700	91.9	>30	12	>30	>30	>30

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TABLE IX. CURRENT OR PLANNED FEDERAL STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Source	Status	Standard	Reference
Steam generators; heat input >263 GJ/hr (250 MBtu/hr)			
Gaseous fossil fuel – fired	Promulgated 12-23-71	86 ng/J (0.2 lb/10^6 Btu)	36 FR 24877
Liquid fossil fuel – fired	Promulgated 12-23-71	130 ng/J (0.3 lb/10^6 Btu)	36 FR 24877
Solid fossil fuel – fired (except lignite)	Promulgated 12-23-71	300 ng/J (0.7 lb/10^6 Btu)	36 FR 24877
Mixed fossil fuel – fired	Promulgated 12-23-71	$\frac{86X + 130Y + 300Z^{a}}{X + Y + Z}$ ng/J	36 FR 24877
Lignite coal – fired	Proposed 12-22-76	260 ng/J (0.6 lb/10^6 Btu)	41 FR 55792
Wood residue – fired	Amended 11-22-76	Add wood residue to permissible mixed fuel firing standard	41 FR 51397
Bituminous coal – fired	SSEIS^{b} under review	260 ng/J (0.6 lb/10^6 Btu)	
Gas turbines; heat input >7.9 GJ/hr (7.5 MBtu/hr)	SSEIS under review	75 ppm (15 percent O_2)	
Stationary IC engines	SSEIS under review		
Intermediate sized steam generators	Under study		

[a] X, Y, and Z are the percent of total heat input derived from gaseous, liquid and solid fossil fuels.

[b] Standard Support and Environmental Impact Statement.

TABLE 5. SUMMARY OF COMBUSTION PROCESS MODIFICATION CONCEPTS

Combustion Conditions	Control Concept	Applicable Equipment	Effect on Thermal NO_x	Effect on Fuel NO_x	Primary Applicable Controls		
					Operational Adjustments	Hardware Modification	Major Redesign
Decrease primary flame zone O_2 level	Decrease overall O_2 level	Boilers, furnaces	Reduces O_2-rich, high-NO_x pockets in the flame	Reduces exposure of fuel nitrogen intermediates to O_2	Low excess air firing	Flue gas recirculation (FGR)	
	Delayed mixing of fuel and air	Boiler, furnaces	Flame cooling and dilution during delayed mix reduces peak temp.	Volatile fuel N reduces to N_2 in the absence of oxygen	Burner adjustments	Low-NO_x burners	Optimum burner/firebox design
	Increased fuel/air mixing	Gas turbines	Reduces local hot stoichiometric regions in overall fuel lean combustion	Increases	Improved atomization		New can design, premix, prevap.
	Primary fuel-rich flame zone	Boilers, furnaces, IC	Flame cooling in low-O_2, low-temp. primary zone reduces peak temp.	Volatile fuel N reduces to N_2 in the absence of oxygen	Burners out of service, biased burner firing	Overfire air ports, stratified charge	Burner/firebox design for two-stage combustion
Decrease peak flame temperature	Decrease adiabatic flame temperature	Boilers, furnaces, IC, gas turbines	Direct suppression of thermal NO_x mechanism	Ineffective	Reduced air preheat	Water injection, FGR	
	Decrease combustion intensity	Boilers, furnaces	Increased flame zone cooling yields lower peak temp.	Minor direct effect, indirect effect on mixing	Load reduction		Enlarged firebox, increased burner spacing
	Increased flame zone cooling/reduce residence time	Boilers, furnaces	Increased flame zone cooling yields lower peak temp.	Ineffective	Burner tilt		Redesign heat transfer surfaces, firebox aerodynamics
Chemically reduce NO_x in post-flame region	Inject reducing agent	Boilers, furnaces	Decomposition	Decomposition		Ammonia injection possible on some units	Redesign convective section for NH_3 injection

TABLE VI. SUMMARY OF NO_x CONTROL TECHNOLOGY[a]

Equipment/ Fuel Category	Current Technology				Emerging Technology		Comments
	Available Control Technique	Achievable NO_x Emission Level ppm ($lb/10^6$ Btu)	Estimated Differential Annual Cost	Operational Impact	Near Term 1977-1985	Far Term 1985-2000	
Existing coal-fired utility boilers	LEA + OSC (BBF, BOOS, OFA); new burners	[illegible]	[illegible]	Possible increase in corrosion & slagging & carbon in flyash	Advanced low NO_x burners	Ammonia injection, flue gas treatment	Ammonia injection, FGT potential supplement to CM if needed
New coal-fired utility boilers	LEA + OFA, new burners	[illegible]	[illegible]	No major problem with tangential design; other designs now coming on line	Low NO_x burners or advanced staging concepts	Optimized burner/firebox design; fluidized bed combustion; ammonia injection	Same as above
Existing oil-fired utility boilers	LEA + OSC + FGR, load reduction	[illegible]	[illegible]	Possible flame instability; boiler vibration	Low NO_x burners, oil denitrification	Ammonia injection, flue gas treatment	No new units; emission levels are limit of current technology
Existing gas-fired utility boilers	LEA + OSC + FGR, load reduction	[illegible]	[illegible]	Possible flame instability; boiler vibration	Low NO_x burner	Ammonia injection, flue gas treatment	No new units; emission levels are limit of current technology
Oil-fired industrial watertube boilers	LEA + OSC (BBF, BOOS, OFA)	[illegible]	[illegible]	~1% increase in fuel consumption, flame instability, boiler vibration (marginal)	Low NO_x burners, [illegible] in new unit designs, oil denitrification	Optimized burner/firebox design, ammonia injection	Current technology still being developed

TABLE VI. Continued

Equipment/ Fuel Category	Current Technology				Emerging Technology		Comments
	Available Control Technique	Achievable NO$_x$ Emission Level ng/J (lb/10^6 Btu)	Estimated Differential Annual Cost	Operational Impact	Near Term 1977-1985	Far Term 1985-2000	
Stoker-fired industrial watertube boilers	LEA + OFA	150-190 (0.35 - 0.45)	[illegible]	Possible ~1% increase in fuel consumption; corrosion; slagging of grate (retrofit)	Inclusion of OFA in new unit design	Fluidized bed combustion; ammonia injection	Current technology still being developed
Gas-fired industrial watertube boilers	LEA + SSC (OFA, BOOS, BBF)	86-130 (0.2 - 0.3)	[illegible]	~1% increase in fuel consumption; flame instability; boiler vibration (retrofit)	Low NO$_x$ burners; OFA in new unit design	Optimized burner/firebox design; ammonia injection	Current technology still undergoing development
Industrial firetube boilers	LEA + FGR; LEA + SSC	65-110 (0.15 - 0.25)	[illegible]	~1% increase in fuel consumption; flame instability (retrofit)	Low NO$_x$ burners; OFA or FGR in new unit design	Optimized burner/firebox design	Development continuing on current technology
Gas turbines	Water, steam injection	110-150 (0.25 - 0.35)	[illegible]	~1% increase in fuel consumption; effects only thermal	Advanced combustor designs for dry NO$_x$ controls	Catalytic combustion; advanced can designs	Current technology widely used

TABLE VI. Concluded

Equipment/ Fuel Category	Current Technology				Emerging Technology		Comments
	Available Control Technique	Achievable NO_x Emission Level ng/J ($lb/10^6$ Btu)	Estimated Differential Annual Cost	Operational Impact	Near Term 1977-1982	Far Term 1983-2000	
Residential furnaces	Low NO_x burner/ firebox design (oil)	25-43 (0.06 - 0.10)	$0.14-0.28/ [illegible] ([illegible] x 10^6 BTU/hr)	~5% decrease in fuel consumption	Advanced burner/fire-box design (gas & oil)	Catalytic combustion	Current technology still being tested
IC engines	Fine tuning, changing A/F	1,070-1,290 (2.5 - 3.0)	[illegible] ([illegible] BHP)	5-10% increase in fuel consumption; misfiring; poor load response	Include moderate control in new unit design	Advanced head designs	Technology still being tested
Industrial process furnaces	LEA	85-215 (0.2 - 0.5)	Unknown	Unknown	Low NO_x burners, development of external controls (FGR, [illegible]) on retrofit basis	Possible inclusion in new unit design	Control development in preliminary stages

TABLE VII. SUMMARY OF POTENTIAL POLLUTANT/COMBUSTION SOURCE HAZARDS

Pollutant Class/Group	Combustion Source	Emission Exceeds Potential Hazard Threshold	Emission Exceeds 10X of Potential Hazard Threshold
Vapor Phase Hydrocarbons			
Total	IC Engines		X
Aldehydes	Utility Boilers, all Fuels		X
	Oil-Fired Industrial Boilers	X	
Carboxylic Acids	Coal-Fired Utility Boilers	X	
One-Ring Aromatics	Utility Boilers, all Fuels	X	
Particulates	Coal-Fired Boilers	X	
	Oil-Fired Industrial Boilers		X
Sulfates	Coal- and Oil-Fired Utility Boilers	X	
Organics			
Anthracene	Oil-Fired Boilers	X	
	Coal-Fired Residential Units	X	
	Coal-Fired Utility Boilers		X
Pyrene	Coal-Fired Residential Units	X	
	Boilers, all Fuels		X
Benzo(a)pyrene	Coal-Fired Residential Units	X	
	Coal-Fired Industrial Boilers		X
Benzo(e)pyrene	Coal-Fired Residential Units	X	
	Coal-Fired Boilers		X
Perylene	Coal-Fired Residential Units	X	
Trace Metals			
Be	Coal-Fired Utility Boilers	X	
Cd	Coal-Fired Utility Boilers		X
Co	Oil-Fired Utility Boilers		X
Cr	Coal- and Oil-Fired Utility Boilers	X	
Ni	Oil-Fired Utility Boilers	X	
Pb	Coal- and Oil-Fired Utility Boilers		X
V	Oil-Fired Utility Boilers	X	
	Coal-Fired Utility Boilers		X
Zn	Coal-Fired Utility Boilers		X

TABLE XIII. EVALUATION OF INCREMENTAL EMISSIONS DUE TO NO_x CONTROLS APPLIED TO BOILERS

NO_x Control	Incremental Emission						
	CO	Vapor Phase HC	Sulfate	Particulate	Organics	Segregating Trace Metals	Nonsegregating Trace Metals
Low Excess Air	++	0	+	0	++	+	0
Staged Combustion	0	0	+	+	++	+	0
Flue Gas Recirculation	0	0	+	+	+	+	+
Reduced Air Preheat	0	0	+	0	+	0	+
Reduced Load	0	0	+	0	+	0	0
Water Injection	0	0	+	+	+	0	0
Ammonia Injection	0	0	++	+	0	+	0

Key: ++ denotes high potential for increased emissions
+ denotes medium potential
0 denotes low potential

TABLE IX. EVALUATION OF SOURCE PRIORITIES

Source Category	Major Design Types[a]	Minor Design Types[a]	Degree of Control Implementation	Nationwide NO_x Emission Ranking	Relative Impact Potential[b]	Source Control Need/Effectiveness[b]		Source Ranking
						New Sour.	Ret. Sour.	
Coal-fired utility	Tangential, single and opposed wall-fired, turbo	Cyclone, vertical, stoker	All new sources, moderate for existing sources	1	H	H	H	1
Oil-fired utility	Same as above	Cyclone	Extensive for existing sources	4	H	H	L	2
Gas-fired utility	Same as above		Same as above	3	L	H	L	[illegible]
Coal-fired watertube	Pulv., Stoker-spreader	Underfeed/overfeed	Low for existing, impending for new	5	H	H	H	[illegible]
Oil-fired watertube	Single and multiburner		Same as above	10	H	H	H	[illegible]
Gas-fired watertube	Single and multiburner		Same as above	7	L	H	[illegible]	[illegible]
Coal-fired firetube		Stoker	Same as above	14	H	H	L	[illegible]
Oil-fired firetube	Scotch	Firebox, HRT	Same as above	8	H	H	H	5
Gas-fired firetube	Scotch	Firebox, HRT	Same as above	9	L	H	[illegible]	[illegible]
Gas- and oil-fired gas turbines	Industrial, utility, simple cycle	Comb. cycle regenerative	Moderate for existing sources, impending for new sources	11	L	H	[illegible]	[illegible]
Gas- and oil-fired warm air furnaces	Res., Com. furnace	Space heaters	Increasing use for energy conservation	12	[illegible]	H	[illegible]	7
Compression ignition IC engines (diesel fuel and mixed)	Turbocharged	Blower scavenged	Negligible for existing sources, impending for new sources	6	[illegible]	H	[illegible]	[illegible]
Spark ignition IC engines	Turbocharged, naturally aspirated		Same as above	2	[illegible]	H	H	[illegible]
Industrial process combustion	Process heaters, furnaces, kilns		Negligible	13	[illegible]	H	[illegible]	[illegible]

[a] Major refers to sources likely to be controlled for NO_x; minor refers to sources for which controls are unlikely to be implemented.

[b] H = high, M = medium, L = low.

TABLE 1. SUMMARY OF SOURCE CONTROL PRIORITIES

[illegible]

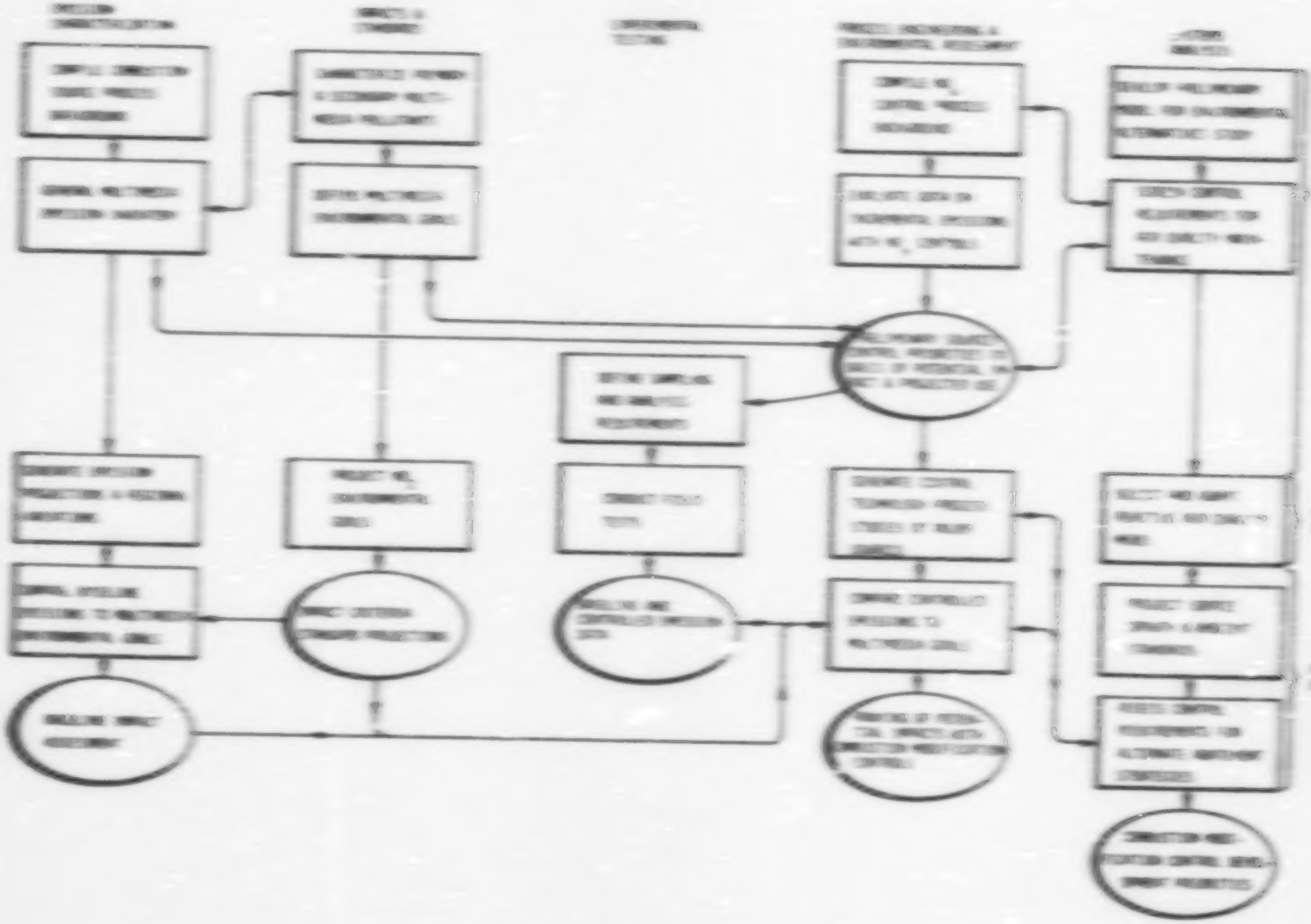


Figure 1. NO_x E/A program approach.

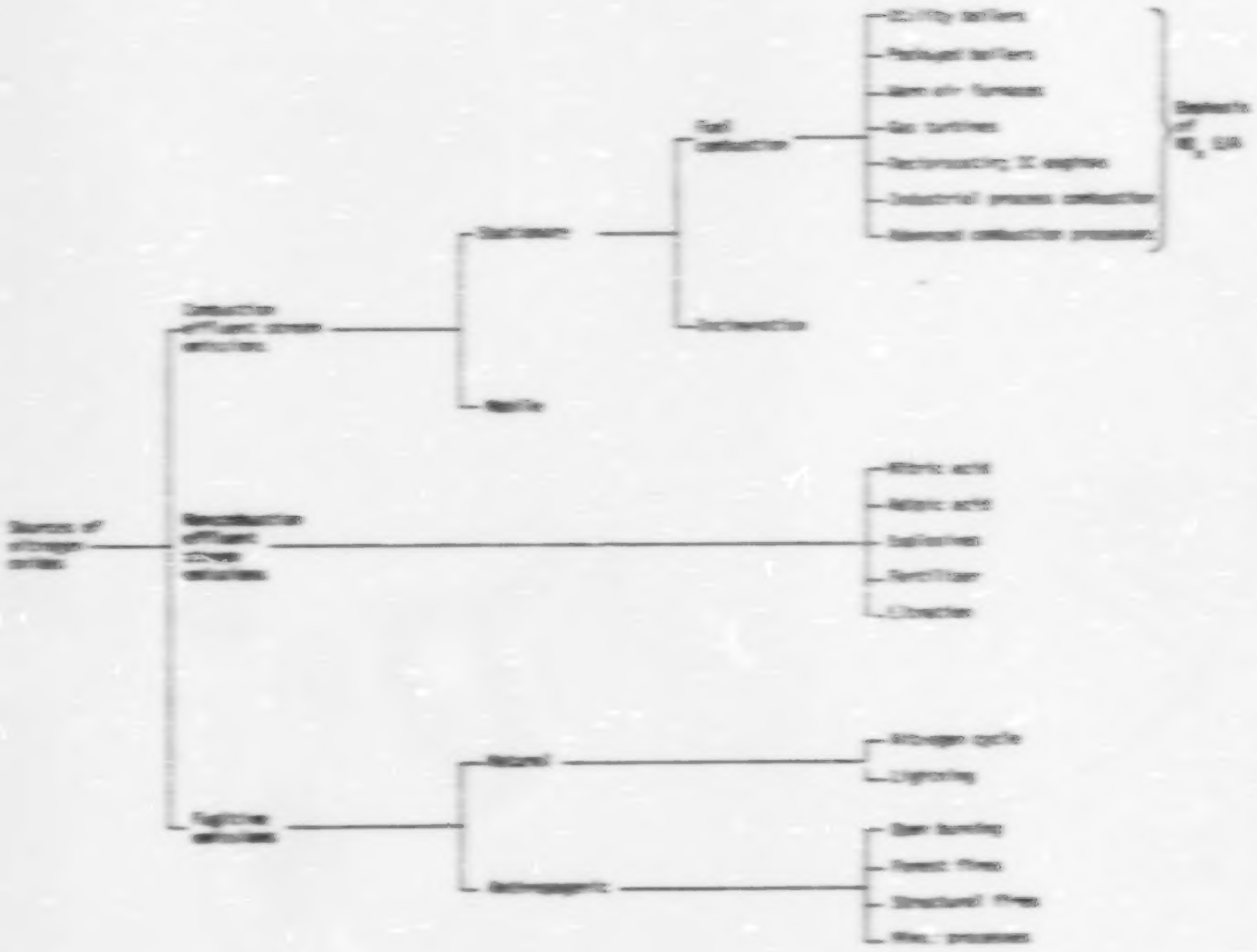
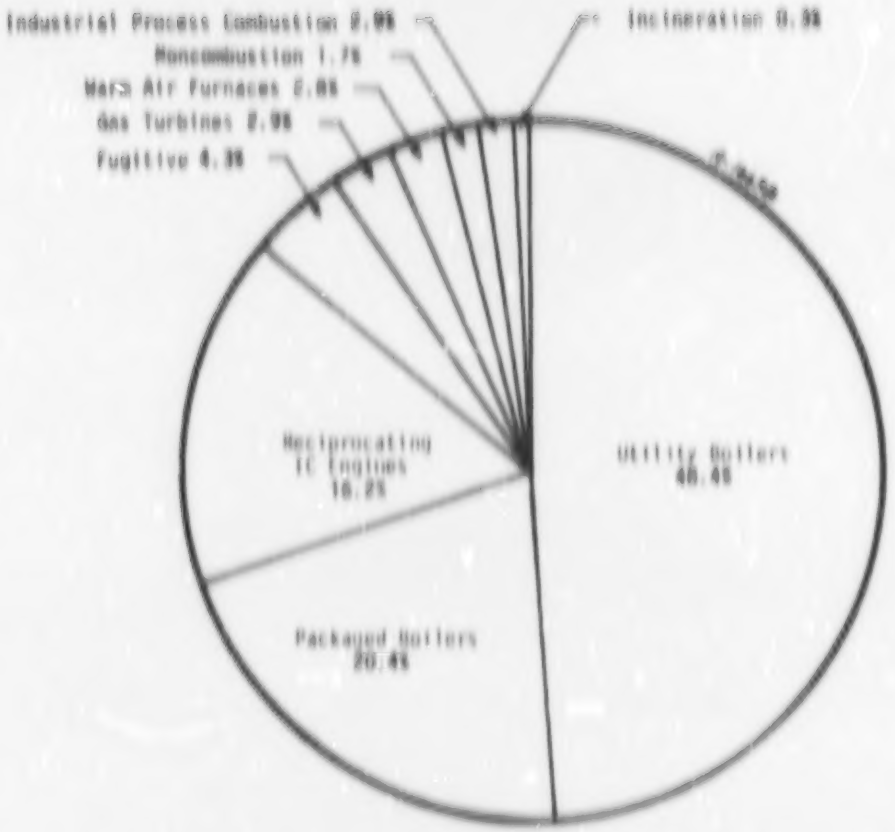

Sources of nitrogen oxides
Combustion effluent stream emissions
Stationary
Fuel combustion
Utility boilers
Packaged boilers
Warm air furnaces
Gas turbines
Reciprocating IC engines
Industrial process combustion
Advanced combustion processes
Incineration
Mobile
Noncombustion effluent stream emissions
Nitric acid
Adipic acid
Explosives
Fertilizer
Fugitive emissions
Natural
Nitrogen cycle
Lightning
Anthropogenic
Open burning
Forest fires
Structural fires
Misc. processes

Figure 2. Sources of nitrogen oxide emissions.



1974 Stationary Combustion Source NO_x Emissions

	1,000 Mg	1,000 Tons	Percent Total
Utility Boilers	5,553	6,116	48.4
Packaged Boilers	2,345	2,583	20.4
Warm Air Furnaces	321	353	2.8
Gas Turbines	338	372	2.9
Reciprocating IC Engines	1,857	2,045	16.2
Industrial Process Combustion	333	367	2.9
Noncombustion	193	212	1.7
Incineration	40	44	0.3
Fugitive	496	546	4.3
TOTAL	11,478	12,649	100

Figure 3. Distribution of stationary anthropogenic NO_x emissions for the year 1974 (stationary fuel combustion: controlled NO_x levels).

SESSION I:

SMALL INDUSTRIAL, COMMERCIAL AND RESIDENTIAL SYSTEMS

ROBERT E. HALL
CHAIRMAN

DESIGN OPTIMIZATION AND FIELD VERIFICATION OF AN INTEGRATED RESIDENTIAL FURNACE

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ABSTRACT

The purposes of this project are: (1) to further optimize the design of an integrated, low-emission high-performance residential warm-air oil furnace, a prototype version of which has been used earlier for proof-of-concept demonstration of burner and firebox design principles and (2) to verify its pollutant emissions and thermal efficiency performance in actual residential installations over an entire winter-heating season.

The project is being conducted in two sequential phases. The first phase has involved analysis and laboratory testing to further optimize the furnace design and to document its pollutant emissions and thermal efficiency performance. The goal of this phase was to achieve a commercially producible design that is safe for use in residences. The optimized furnace's capabilities to operate with alternate fuels also are being evaluated. In preparation for the next phase, the logistics of residential field testing have been delineated and appropriate arrangements made.

The second phase of the project is just getting underway and will be concerned with: construction of a number of integrated furnace units to be field tested, their installation in selected residences, and their operation during an entire annual heating season. The emission and performance characteristics of each test unit will be determined initially and remeasured monthly. Any tendency for drift in emissions or performance will be allowed to continue from month to month without corrective adjustments unless it is necessary to correct an unsafe condition or one producing excessive pollutant emissions.

The paper summarizes the results of the first-phase laboratory investigations and describes the plans for field testing. It is based upon work performed

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for the U.S. Environmental Protection Agency under Contract 68-02-2174. The EPA Contract Officer was Mr. G. Blair Martin, Combustion Research Branch, Industrial Environmental Research Laboratory, Research Triangle Park, North Carolina.

INTRODUCTION

Under a previous EPA contract, design criteria were determined whereby gun-type pressure-atomizing oil burners, such as are commonly used in residential and commercial space-heating systems, may be modified so that they produce substantially lower emissions of oxides of nitrogen (NO_x) and burn smoke free at more efficient operating conditions. Those design criteria were used to modify existing burners of two sizes--a 1.05 ml/s (1.0 gph) residential burner and a 9.47 ml/s (9.0 gph) commercial burner--and were shown to be valid in laboratory testing (Ref. 1).

Further laboratory research with the smaller of those two low-emission burners provided additional design criteria for fireboxes matched to the burner to achieve even lower NO_x emissions (Ref. 2). Thereafter, proof-of-concept experiments were carried out in the laboratory using a prototype residential warm-air furnace embodying the several design criteria (Ref. 3 and 4). The resultant NO_x emissions were reduced to about 35% of the estimated average from comparable, existing, installed units. Further, the laboratory performance data showed that the prototype furnace's cyclical efficiency should be 10 or more percentage points higher than the estimated average of the existing residential oil furnace population.

The present investigation is a logical continuation from those encouraging laboratory results. Potential benefits of commercializing the derived technology are to be demonstrated by conducting field tests of several low-emission furnaces in actual residences. First, however, it was appropriate to effect further refinements of the burner and furnace designs, partially to further optimize emissions and efficiency performance and partially to improve commercial producibility. Thus the two objectives were: (1) beginning with the prototype furnace tested earlier, to further optimize the design of an integrated, low-emission high-performance oil-fueled residential warm-air furnace, and (2) to verify its pollutant emissions and thermal efficiency performance by operating units over an entire winter heating season in actual residential installations.

Further design optimization was approached by making modifications to the prototype low-emission furnace described in Ref. 5, and retesting the unit in a Rocketdyne laboratory. Eventually, this led to the construction and verification testing of a second, all-new integrated furnace unit prior to assembly of six units of the final design to be installed in the field. Simultaneously pursued was the definition of requirements for selecting test locales, arranging for local support, selecting host residences, and the logistics of shipping, installing, activating, servicing, measuring performance and, finally, removing the experimental furnaces and restoring the host homes' heating systems to their former conditions.

At the time this paper is presented, all the preparatory work will have been completed and the test units will be ready for installation and initiation of the field test period. Thus, this paper constitutes a progress report on the design finalization and the arrangements made for the field verification.

SUMMARY OF THE PROTOTYPE FURNACE INVESTIGATION

The experimental furnace unit tested previously (Ref. 3 and 4) has been called a "prototype optimum furnace." For clarity in this paper, that earlier test unit will be designated the "prototype furnace" and the further optimized unit derived from it will be referred to as the "integrated furnace." In this section are given brief descriptions of the prototype furnace and the laboratory facility in which it was tested, followed by a summarization of its emissions and efficiency performance.

PROTOTYPE FURNACE DESCRIPTION

The prototype test unit was based on modifying or replacing several specific components in a commercially available warm-air oil furnace of contemporary design*. The prototype furnace and the advanced technology modifications made to achieve it are illustrated in Fig. 1. The central line drawing is an interior side view of the furnace; the front is on the left-hand side. Each of the photographs surrounding the drawing illustrates a modification made and an arrow denotes its location in the furnace assembly.

The optimum burner head is illustrated alone although, in actuality, the furnace's entire burner was replaced with the optimum burner that had been tested extensively before, rather than replacing only the head. The combustion air fan in the replacement burner was also fitted with a quiet stator plate to prevent coupling of combustion air flow pulsations to combustion in the chamber.

The unit's original firebox, a rather typical 0.249 meter (9.75 inch) inside-diameter refractory-fiber-lined design, was replaced by a larger 0.432 meter (17 inch) inside-diameter uninsulated air-cooled firebox. Its outside surface was heavily finned to ensure adequate heat extraction from the flame zone, a key contributor to the reduction of NO_x emissions. The machined and welded mild steel prototype firebox was more massive than its predecessor by about 50 kg (110 lbm) and so constituted a substantial heat sink. Built as an experimental tool, the firebox was intentionally overdesigned in the interests of maintaining wall temperatures as nearly uniform as possible and retaining high wall temperatures during standby.

Two related modifications were concerned with the combustion air supply. First, combustion air was admitted to the furnace through a "sealed air" supply system, adopted from Ref. 5. Simply stated, this means that combustion air, together with air drawn into the flue through a barometric pressure control damper, is brought in from outdoors rather than consuming heated (and perhaps humidified) air from within the residence. Pollutant emissions usually are not influenced by this change, but fuel consumption may be reduced by 5 to 10% or more (Ref. 5). Second, a separate filter was provided for the combustion air so that the burner could be tuned for operation with close to minimum (~15%) excess air without an accumulation of lint, hair, etc., on the burner air passages, fan blades, or head forcing it into a smoky and/or high CO condition.

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*A Lennox Model O11-140 furnace, supplied by Lennox Industries, Inc., was utilized.

The combustion air inlet to the burner was fitted with a weighted damper which closed automatically when the burner was turned off. It was designed to eliminate the draft air loss of heat up the flue during furnace standby. Fuel savings effected by this device will probably average between 2 and 3%. This device also included a separate butterfly damper whose position controlled the flow of combustion air.

Minor modifications also were made to a few other furnace components. Louvers in the burner vestibule closure panels were covered to make the vestibule part of the sealed air system. Inside the cabinet, some minor structural reinforcement was added to support the heavier firebox, and flat, vertical-panel baffles were added in the warm-air passage to force the warm air to flow over the finned firebox. Otherwise, the warm air blower and filter, the compact heat exchanger, the furnace cabinet, and all electrical circuits and controls were left unchanged from the original stock furnace.

LABORATORY FACILITY

Performance of the prototype furnace was evaluated in an outdoor laboratory facility having provisions for measurement of pollutant emissions, operational characteristics, and thermal efficiency. Figure 2 is a schematic of the furnace evaluation system; it shows the installation of gas and air flow ducting and a variety of instrumentation. Basic thermal performance measurement techniques conformed with requirements of ANSI Z91.1-1972 (Ref. 6). Other instrumentation were added to provide (1) enlarged understanding of furnace behavior and (2) data for calculating cycle-averaged thermal efficiency.

Constituents in the flue gases were measured by continuously withdrawing a gas sample from the center of the flue, at the location denoted in Fig. 2, and passing it through an analysis train. The analytical system provides for manual spot samples for smoke and for continuous analyses for O_2, CO_2, CO, NO, and unburned hydrocarbons (UHC) species remaining in the dry gases after their passage through condensible traps, filters, and driers. Detailed information on the setup and operation of the train, instruments used and their ranges, data processing, etc., has been given previously in Ref. 1 through 3.

The furnace flue thermal losses were determined by making measurements to support flue gas heat balances. Combustion gas mass flowrate was back-calculated from measured fuel flowrate and stoichiometric ratio (as determined from flue gas composition measurements). The flue gas exhaust temperature was measured in an insulated flue pipe with a thermocouple located 0.46 meters (18 inches) above the centerline of the heat exchanger flue exit. Flue draft, gas composition, and smoke measurements were taken at successive 0.0317-meter (1.25-inch) increments downstream of the thermocouple, respectively.

Steady-state thermal efficiencies were derived from the steady-state flue gas temperatures and CO_2 concentrations (Ref. 6). During cyclical operation in which steady-state was not reached, values for those parameters just prior to burner cutoff were used in the same manner to get approximations of steady-state efficiencies. Burner firing times of 10 minutes gave such pseudo-steady-state efficiencies that were indistinguishable from those derived from steady-state measurements; those calculated from 6-minute burner firing time data were approximately 1% higher than the steady-state efficiencies due to heat being absorbed by the cool furnace components resulting in a lower flue gas temperature.

Data were also measured to support calculation of cycle-averaged efficiencies. However, the variable ambient air temperature in the outdoor facility introduced considerable scatter in the data (Ref. 3). Indicated differences between the mean steady-state and mean cycle-averaged efficiencies were smaller than that scatter, so steady-state was used as the main basis for comparison.

PROTOTYPE FURNACE RESULTS

Pollutant Emissions

Prototype furnace gas concentrations of nitric oxide are plotted versus stoichiometric ratio in Fig. 3. A shaded region near the middle of the graph indicates that a large majority of existing residential oil furnaces release between 1.3 and 2.2 g NO/kg fuel burned. An estimated existing furnace average of 1.8 g NO/kg fuel may be used for evaluating the potential impact of applying candidate NO_x reduction techniques.

Measured NO emissions from the stock furnace fell on the high side and above that typical range; at a nominal 50% excess air operating point, it produced 2.2 g NO/kg fuel burned. Measured NO emissions from the prototype furnace were much lower, falling between 0.5 and 0.75 g NO/kg fuel over the stoichiometric ratio range of interest. Tuned to the intended normal operating condition with only 15% excess air, the unit produced 0.61 g NO/kg. That corresponds to reductions of about 72 and 65%, respectively, from NO_x emissions produced by the stock furnace (at its nominal operating point) and by the average estimated for all existing installed units.

Carbonaceous emissions from the prototype furnace unit also were acceptably low at those conditions, as indicated by the lower than No. 1 smoke. A comparison of values in Table 1 shows that CO and hydrocarbon emission levels from the prototype furnace were somewhat higher than those measured for the stock furnace but were quite comparable with the average tuned values measured in the field survey of Ref. 7.

Efficiencies

Pseudo-steady-state efficiencies for the prototype furnace are compared with those for its stock predecessor in Fig. 4 by superimposing values calculated from 6th-minute data in cyclical runs on an efficiency decrement plot. The performance curve for the original stock furnace fell well below (i.e., higher efficiencies) the shaded band representative of a large majority of existing installed residential heating units. The stock unit could be tuned to a moderately low 30% excess air nominal operating condition where its net flue gas temperature averaged only 160 C (325 F). The resultant steady-state gross thermal efficiency was 82.5% (i.e., the stock furnace was among the higher performing units in the existing population).

Thermal efficiency levels achieved by the prototype furnace were qualitatively the same as those of the stock furnace. However, as is evident in Fig. 4, flue gases leaving the prototype unit were 40 to 55 C (75 to 100 F) hotter than those from the stock furnace, and the efficiency decrement due to the higher net flue gas temperature was offset by operating the prototype unit at substantially lower stoichiometric ratio. This apparently anomalous behavior was believed to be caused by warm-air jets outside of the firebox bypassing some of the main heat exchanger, a condition which was thought to be relatively easy to correct.

The 82 to 83% pseudo-steady-state thermal efficiency exhibited by the prototype furnace was close to the maximum achievable in noncondensing flue gas residential systems. Taken alone, this is not unique, since comparable efficiencies are attained by some current commercially available units (as exemplified by the stock furnace that was converted into the prototype). What is unique and important about it is the demonstration that near-maximum steady-state efficiency and near-minimum NO_x emissions can be obtained simultaneously.

INTEGRATED FURNACE DESIGN OPTIMIZATION

The prototype furnace test results confirmed the feasibility of applying the several newly developed, low-emission oil burner and firebox design criteria to residential space heating equipment. The experimental prototype unit came very close to satisfying all of the pollutant emission and efficiency objectives for which it was designed. Operationally, its behavior was quite comparable with current commercially available furnaces. A 500-hour duration test, equivalent to about one-tenth of an average heating season, indicated that the unit might serve through an entire winter heating season without requiring substantial maintenance and without exhibiting appreciable shifts in operating conditions or pollutant emission levels. Before undertaking such a next logical step in the proof-of-concept demonstration of the furnace design criteria, however, it was appropriate to further improve some features of the prototype unit.

MODIFICATIONS FOR THE INTEGRATED FURNACE

Optimum Burner

The standby draft control device for the combustion air inlet to the burner was redesigned. The butterfly valve was removed and air flow control was accomplished by providing a mechanical stop to limit the opening of the weighted flap damper. A microswitch was incorporated in the stop to provide a positive electrical indication that the draft flap opens when the burner is turned on; the burner control circuitry was redesigned to take advantage of this safety feature.

An internal clutch was inserted in the burner's drive shaft for the fuel pump. The reason was to give a quicker cutoff of fuel flow through the oil nozzle and better eliminate post-firing dribble.

A stamped annular sheet metal ring was added to the sheet metal burner head and welded to the external face of its choke plate. In addition to improving the burner head's appearance, this improved the alignment of the head with respect to the blast tube and oil nozzle and also eliminated leakage of ~15% of the combustion air through cracks and holes at the head's perimeter. The modified head and combustion air inlet assembly are illustrated in Fig. 5.

Finned, Air-Cooled Firebox

The fabricated steel firebox, with its large external steel fins welded to a 0.64-cm (0.25-inch) thick steel shell was inordinately expensive to make, heavier than desirable and, as well, extracted more than the designed-for quantity of heat from the flame zone. Therefore, it was replaced with a lighter weight, cast-formed combustion chamber. Serious consideration was given to making a cast aluminum firebox. The coefficient of thermal expansion for aluminum is high enough, however, that rather high stresses were calculated at the roots of the fins and at the firebox-to-heat-exchanger joint. In principle, yield conditions could be avoided by maintaining low wall temperatures but, even then, cycle-fatigue failure was predicted to lead to an unacceptably short firebox lifetime of 3 to 5 years. Therefore, a cast iron was selected as the firebox construction material.

A photograph of the cast-iron firebox is shown in Fig. 6. The internal dimensions and burner insertion port duplicate those of the fabricated steel combustor; otherwise, the designs are quite different. To facilitate welding the stock fabricated steel heat exchanger to the cast-iron firebox, a rolled steel ring is cast integrally into the wall of the firebox discharge opening. This provides a positively sealed joint as well as a much smoother surface for the external air to flow over. All of the cast external fins are shorter than were the fabricated ones, and both their heights and spacings are graduated to promote more-nearly uniform wall temperatures. The shorter fins were designed to extract a lower fraction of the overall heat transfer from the firebox; the cast wall temperatures were expected to be about 56 C (100 F), on the average, higher than those of the former finned steel firebox. The cast firebox, together with its support legs and burner mounting plate, has a mass of 34 kg (75 lbm).

Warm-Air Coolant Distribution

The vertical panel baffles positioned close to the fin tips in each side of the prototype furnace's firebox were reshaped to improve the air-flow distribution to the outside of the main heat exchanger. The baffles were bent slightly at about the midsection of the firebox to begin a gradual flaring from the constricted cross section to the full heat exchanger cross section. The location of each baffle remained the same; however, since the fins were shortened, this placed them about 0.064 meters (2.5 inches) from the nearest fin tip, as opposed to nearly touching in the prototype furnace. Also, new baffle panels were added adjacent to the outer side panels of the heat exchanger section. This was done to reduce the flow gaps between the heat exchanger and the wall by 0.025 meter (1.0 inch), thereby reducing bypass (i.e., no heat transfer) air flow. These changes were made to restore the coolant air to the outer sections of the heat exchanger to improve the overall heat transfer of the furnace.

LABORATORY TESTS OF THE INTEGRATED FURNACE

A first specimen of the integrated furnace was built by converting the prototype furnace via the foregoing modifications. It was tested in the same laboratory facility and with the same procedures as was the prototype unit. A basic test matrix provided for measurement of pollutant emissions and performance as functions of burner firing rate, overall stoichiometric ratio, combustion air supply temperature, firebox draft, and warm-air flowrate. The test plan also allowed for retesting in the event that one or more components needed further refinements. Discussion of the extent to which this option was needed is included with the description of test results, below.

In addition to hot-firing the integrated furnace, cold-flow tests of the burner were used to measure the effects on the combustion air fan characteristics of several complications added to the stock* burner's combustion air circuit.

Laboratory Test Results

Burner Blower Characteristics. The combustion air blower's characteristics were measured to establish the operational limits of the combustion air system. Tests were made with the air flow throttled either at the air inlet or at the exit. This was done by mounting the burner inside or outside, respectively, of a large sealed compartment and measuring the compartment pressure and air flow into or out of it. A calibrated laminar flow element was used for accurate measurement of air flows.

Throttled outlet characteristics are shown in Fig. 7. The uppermost curves show that the presence of the quiet-stator has very little effect on the blower's basic throughput characteristic. Successively lower curves show how the achievable air flow is impacted by adding, in sequence, the inlet draft flap assembly, a static disc within the blast tube, and the optimum head to complete the burner assembly. Dashed lines indicating pressure drops of the head, static disc, and draft flap were obtained by subtraction of appropriate characteristic curves. The nominal design operating point, with a firing rate of 1.05 ml/s (1.00 gph) and a stoichiometric ratio of 1.15, is indicated by an arrow at 0.0125 m^3/s (26.5 scfm). To achieve that flowrate without throttling the exit, the firebox would have to be pressurized to about 60 N/m^2 (0.24 inch water column). The usual residential furnace practice, however, is to throttle the inlet to the blower, rather than pressurizing the firebox or throttling the exit.

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*The R. W. Beckett Co.'s Model AF burner was the stock unit underlying the optimum burner.

Effects of throttling the blower inlet (i.e., limiting the draft flap opening) are shown in Fig. 8 along with the effects of imposing a negative (suction) pressure condition on the air supplied to the inlet. The latter condition is encountered sometimes in conventional furnace practice by operating a furnace in a fairly leak-tight room or house, so that the burner blower reduces the pressure in the furnace enclosure. In the integrated furnace, pressure in the sealed burner vestibule also will be below ambient outdoor pressure by the pressure drop of the air supply system.

The throttled inlet characteristic curves show that, if the burner inlet is at sea level pressure, the nominal design conditions can be achieved with the draft flap only one-eighth open; opening it further should allow tuning for stoichiometric ratios (SR) from 1.15 to about 1.35. Reducing the inlet pressure exerts a linear reduction effect on the achievable flowrate; again, the margin of adjustability from the design point would be eliminated by about 60 N/m^2 (1/4 inch water column) suction at the blower inlet. This condition is not likely to occur unless the combustion air filter is allowed to become very dirty.

What the burner requires is a given *weight* of air for a given firing rate and stoichiometric ratio. What the blower supplies is a given *volume* of air at its local (nominally inlet) conditions. If the furnace is installed at a high altitude, a greater volume must be delivered to obtain the required weight of air. The optimum burner, fired at 1.05 ml/s (1.0 gph) and a 1.15 SR, would have a fully open inlet and no margin of adjustability at about 1500 meters (4900 feet) elevation. In practice, the furnace would have to be downrated to a lower firing rate or supplied with a higher capacity blower to allow servicemen at those altitudes some margin of tuning control.

Pollutant Emissions. During most of the testing of the initial integrated furnace, obtained by conversion of the former prototype unit, the measured emissions of air pollutant species were not significantly different than those reported earlier (Table I and Fig. 3) for the prototype furnace. However, as those tests were nearing completion and a second, newly constructed integrated furnace was being readied for verification testing, it was discovered that the Bacharach smoke tester was malfunctioning due to a cracked piston cap and a faulty check valve. Thus, the indicated smoke readings were low for the then current tests and for previous tests over some indeterminant time period.

Because of the conversion sequence from the original stock Lennox to the prototype to the integrated furnace, it was not possible to go back and retest those earlier configurations. However, the original stock Lennox burner was tested in a second stock Lennox furnace and several exploratory modifications were made to the integrated furnace and its optimum burner to simulate the prototype configuration. It was concluded from the results that the problem with the smoke meter probably developed sometime between the stock Lennox furnace tests and the prototype furnace tests reported in Ref. 3. That is, the prototype unit's smoke emissions actually must have been appreciably higher than were reported. This put a serious question on the integrated unit's capability to be tuned to the nominal (15% excess air) design point.

The integrated furnace was retested, therefore, to determine operating conditions which produce acceptably low smoke. Some of the results are plotted in Fig. 9. At the 1.05-ml/s (1.0-gph) firing rate, smoke emissions were sensitive to excessive over-fire draft conditions and in all cases exceeded No. 1. (Achievable upper values of stoichiometric ratio were restricted by combustion air flow limitations, discussed earlier). At the 0.79-ml/s (0.75-gph) firing rate, there was almost no sensitivity to over-fire draft variations and less than No. 1 smoke was generally measured if excess air exceeded 20%. It was also found that, at this firing level, smoke emissions could be further reduced by inserting the burner head a small distance--0.025 meters (1.0 inch)--into the combustion chamber.

Ostensibly, ≤No. 1 smoke at SR ≥1.15 can be achieved with the latter combination of firing level and burner/firebox configuration. However, the gradient in smoke number with decreasing stoichiometric ratio is quite steep so that attempting to tune the burner to precisely 1.15 SR involves the risk of producing excessive smoke if it is missed, or later drifts, by even a small amount. From these results, it is apparent that the integrated furnace should be rated as a nominal 0.79-ml/s (0.75 gph) unit, rather than the previously stated 1.05 ml/s (1.0 gph), and tuned to burn with about 20% excess air. At these redefined nominal design conditions, the measured steady-state and cycle-averaged emissions of CO were 0.25 and 0.60 g/kg, respectively, and of UHC 0.02 and 0.04 g(as CH_4)/kg, respectively. Measured emissions of NO were somewhat higher than at the former nominal design point, principally because of the stoichiometric ratio change.

Thermal Efficiency. Relocation of the baffles in the warm-air passage around the finned firebox did not produce the expected ~2% increase in thermal efficiency. Several different baffle arrangements were tried, including some in which small local baffles diverted parts of the air flow to better cool hotter sections of the main heat exchanger. Only small variations (~1/4 to 1/2%) in efficiency were indicated and the initial integrated furnace configuration was as good as any other. It was restored, therefore, and attention was turned to the internal distribution of combustion gases within the heat exchanger.

The heat exchanger construction involves six vertical flat-panel elements, three on each side of a central cylindrical dome extension of the firebox cylinder. Combustion gases flow vertically up into the dome, turn 90 degrees into a rectangular exit on the dome's rear wall into a splitter manifold which turns them through 180 degrees and distributes them among the six panels. Flow out of the panels is collected in a manifold at the front of the furnace, from which it is ducted into the vertical flue. A set of holes was drilled in the flue gas collector manifold to permit measurement of the temperatures of the gases leaving the several panels. Traverses made with a long chromel-alumel thermocouple revealed quite large temperature differences among the panels and strong gradients within each panel. In general, the gases were hottest in the outermost panels and coolest in the innermost ones and, in each panel, were much cooler at the bottom than at the top.

Anticipating that making the combustion gas temperatures leaving the panels uniform would maximize overall heat transfer, long vertical vane dampers were designed for insertion in the panel inlets. Initially, only two such dampers were installed, one in each of the outermost panels. With just those two dampers in their most open positions, the range of measured temperatures was reduced from a 269 C (484 F) difference [418 (784) minus 149 C (300 F)] to a 139 C (250 F) difference [343 (649) minus 204 C (399 F)] and the temperature gradients from the panel bottoms to tops were virtually eliminated. Nonetheless, the average flue gas temperature was lowered by only 2 C (3.6 F); this represents less than 0.1% gain in thermal efficiency. This approach was not pursued further.

The experimental evidence suggested that the thermal efficiency of the integrated furnace cannot be increased by improving either the warm air or the combustion gas flow distributions, i.e., a larger heat exchanger is needed to achieve higher efficiency. Because the integrated furnace does have more heat exchange surface (the finned firebox) than the stock Lennox furnace, there remained a question as to why that stock unit exhibited higher thermal efficiency. In an attempt to answer that question, tests were made with a second stock Lennox unit. Although it was manufactured approximately 2 years later, this second unit appeared to duplicate the first one except that the burner head had been redesigned.

The second stock Lennox furnace was fired both with its own burner and with the burner unit from the original stock Lennox unit. In neither case did it achieve anywhere near the low flue gas temperatures (high thermal efficiency) measured earlier with the original stock furnace. In fact, this second stock

Lennox and the integrated furnaces achieved very nearly equal thermal efficiencies at a given stoichiometric ratio. Thus, although the question regarding the performance of the first stock Lennox remains unanswered, it was decided to proceed with preparing field test units of the integrated furnace design without further alterations.

Measured steady-state efficiencies of the integrated furnace at two firing levels are illustrated in Fig. 10. A value of 85 to 86% is indicated at the 0.79 ml/s (0.75 gph) firing rate and 1.20 SR.

FIELD VERIFICATION

As a final step in the proof-of-concept verification process, it is planned to install and field-test six integrated furnaces in selected host residences during the 1977-78 winter heating season. Detailed plans for the field testing have been completed but the test period will not commence until approximately 1 month after this paper is presented. This section, therefore, does not present data but merely describes the approach to and specific plans for field testing.

APPROACH

The basic approach to the field verification testing is to utilize a limited number of integrated furnaces as the space heating sources in as wide a variety as possible of existing oil-fueled residences. Oil heating is concentrated in three general regions of the U.S.: the New England states, the Great Lakes states, and the northern mid-Western states. Because these are all far from Rocketdyne's main plant in California, consideration of several logistics aspects also was involved in selecting test locales.

Test Locale Selection

Three field test units are to be located in each of two test locales where oil heat is used in a substantial fraction of single-family homes and which have distinctly different winter climates. As a start toward selecting the two locales, winter climatic data averaged over several years were reviewed for approximately 35 cities, most of which are distributed throughout the three geographic regions mentioned above. Data considered were: annual and monthly degree days; monthly average temperatures and precipitations; and average diurnal temperature ranges. All cities considered have normal accumulative degree days, based upon 18 C (65 F), exceeding 4500 for the 9-month period of September through May. Monthly average temperature data were plotted directly and on a weighted basis using U.S. census data on the number of households in each city. Mean curves were drawn through these two sets of data and were found to differ by only 1 C (2 F). Comparing the individual cities' weighted monthly averaged winter temperature profiles to the corresponding mean curve, 30 of the 35 cities had annual temperature profiles within ±5% of the mean. Thus, it was inferred that the weighted mean temperature profile is representative for a majority of the households in the colder regions of the 48 contiguous United States.

Based upon their closeness to the weighted mean temperature profile, seven cities were selected as being most representative; they were: Boston, MA; Cleveland and Columbus, OH; Indianapolis, IN; Providence, RI; Scranton, PA; and Springfield, IL. Comparisons of total winter precipitation and diurnal temperature ranges revealed that these cities experience two broadly distinctive winter weather patterns. The *maritime climate*, represented by Boston and Providence, encompasses the eastern seaboard. It probably extends inland for no more than a few dozen miles. Because of its proximity to Lake Erie, Cleveland's climate also falls in that climatic category. The *continental climate*, typical for the inland cities of Springfield, Indianapolis, Columbus and Scranton, is characterized by wider diurnal temperature variations and less total precipitation than are experienced in the maritime climate. It was concluded that one test locale should be selected within each of those two general climatic categories.

Attention was then directed to nonclimatic factors, such as oil usage patterns, predominant types of residential construction, state and local code requirements, and availability of local support. Data concerning pertinent housing characteristics for 11 candidate locates are listed in Table II. Because of the predominant use of oil for residential heating in New England, an assessment was first made of metropolitan Boston as the test locale with a maritime winter climate. From several standpoints, this area was found to be very attractive: there are very broad ranges of house ages, architectural styles, construction materials, degrees of insulation, and wind exposures; nearly all of their central heating systems are oil fueled; the only code requirements imposed on an experimental furnace is that the burner have a Massachusetts approval number; there are reliable, well-established furnace equipment distributors willing to provide installation and service support for field testing; there are several environmental testing laboratories in the area; and, finally, there are regular and convenient travel and shipping connections to Los Angeles, CA. Therefore, Boston was tentatively selected as the maritime climate test locale. Emphasis then shifted to making subcontract arrangements for local installation and service support and laboratory support in Boston and, simultaneously, arriving at a tentative selection of a locale with a continental climate.

It appeared from the initial Boston contacts that laboratory support might be more difficult to arrange than either service support or host homes. It was considered that the larger metropolitan areas were most likely to have qualified, well-instrumented laboratories, so the order of examining cities with continental climates was established as from the larger to the smaller. Thus, even though oil has only a small fraction of residential heating there, Pittsburgh got first consideration. One or two apparently qualified labs were identified and an interested service contractor was found who has a substantial oil-heating background and several oil clients as potential host homeowners. Therefore, Pittsburgh was tentatively selected as the continental climate test locale.

However, as the details of field testing in these specific cities were being formulated and negotiated it was found that the competitive bid responses from analytical laboratories were much higher priced than had been anticipated. Subcontracting of the flue gas analysis effort was then deemed impractical, and an option involving a mobile Rocketdyne instrumentation unit was formulated. It was apparent that with a single mobile unit to cover both test locales, many advantages could be realized with a reduction of the distance between the two locales. A review of the climatic data revealed Albany, NY as an excellent continental climate test site, separated from the Atlantic maritime climate by the Alleghany mountain range, and less than half as far from Boston, MA as Pittsburgh, PA.

The climate in Albany, NY during the heating season is somewhat colder than that in any of the other 10 cities considered in the initial evaluation. The mean temperature of Albany is 5.1 C (41 F) during the heating season as opposed to 6.5 C (44 F) for Boston. The difference between these mean temperatures is actually a little smaller than the difference in the numbers of degree-days listed in Table II. However, both criteria indicate that the thermal load is substantially greater for Albany than for Boston.

Support in Test Locales

Service Support. The selection of the local furnace service support started as a general evaluation of any furnace service contractor in the selected metropolitan areas. However, the process of evaluation quickly revealed that there are advantages to working with distributors of the same brand name (Lennox) furnaces from which the integrated furnace was derived. These service contractors were more knowledgeable in the specifics of the construction, installation, and operation of the stock predecessor unit. The availability of spare common parts through these service contractors reduces the likelihood of unexpected delays. Moreover, many of these franchised service contractors were informed of some Lennox studies on fuel conservation devices, e.g., sealed air systems, which relate to the integrated furnace unit. The final selections of service contractors were made by standard contract bidding procedures and confirmed by visits of Rocketdyne personnel to the candidate organizations.

Selection of Host Sites. A list of potential host dwellings was supplied by each of the two service contractors from their existing customer lists. The selection of the six host sites (single-family dwellings) was based on criteria that included consideration of: (1) dwelling construction, (2) dwelling location, (3) existing dwelling furnace installation, (4) fuel usage history, and (5) host family. The dwellings with basement installations are preferred simply for the ease of accessibility and the space available for instrumentation packages. Other dwelling construction factors (e.g., building materials, age, number of levels, type of insulation, etc.) were considered to obtain a variety of dwellings with varying thermal characteristics. The thermal characteristics of a dwelling can also be influenced by its location where there could be significant localized differences in wind, insulation, heat retention (ground or water), etc. The integrated furnace configuration has been tested at return air flowrates from 0.425 m^3/s (900 scfm) to 0.800 m^3/s (1700 scfm) and return air temperature varying from 10 C (50 F) to 32 C (90 F) with little or no effect upon its operation. Therefore, the existing furnace installations in the candidate dwellings were evaluated primarily on the basis of geometric compatibility with the integrated furnace and the field test instrumentation requirements.

The fuel usage history considered was data for the two previous heating seasons so that correlations with degree-day data could be made to normalize all the thermal efficiency data to one baseline. This correlation may also reveal the necessity for an adjustment factor for changes in lifestyle (e.g., lowering of thermostat settings) induced by recent energy conservation campaigns. The requirement for the host family themselves is stability of the number of occupants during this and the previous two heating seasons. If, for example, there is a college student in say a small family of four, that will not be residing in the house this season, the thermal load upon the heating system may be affected significantly. However, if the student had also been gone in the previous two heating seasons, or if the dwelling is constantly occupied (e.g., kept heated) by another member of the house, the effect would be negligible. The ages of the children were noted as host families without children from 1 to 8 years of age were preferred. The concern here was the likelihood of inquisitive tampering with the instrumentation (e.g., pulling the power cord) by children in this age bracket. Although it is not listed as a criterion, a major influence upon the final selections were the attitudes of the host families toward the field test. Since the field test is of long duration (9 months) during adverse weather conditions and in two different cities, it is very probable that delays will arise, and these could be compounded greatly by an uncooperative host. Therefore, enthusiasm and cooperation are valued traits in the host families.

Integrated Furnace Installations. The installations of the six integrated furnaces are scheduled for the month of September (1977) and all are to be operational by the first day of October. Each installation will involve the removal and storage of the existing furnace and the mounting of the integrated furnace. The warm air ducting will require minor modifications to allow the temporary insertion of a 0.45 x 0.45 x 1.22 meters (18 x 18 x 48 inches) laminar flow element section and various thermocouple probes for cyclic thermal efficiency measurements. A full complement of instruments to evaluate efficiency will be installed on one of the furnaces while the remaining five furnaces will have time event recorders to monitor furnace operations and store this information on magnetic tape (cassette). The thermal efficiency measurement apparatus will be rotated through the other five host sites during the heating season. The field test will terminate at the end of May 1978, at which time the integrated furnaces will be removed and the dwellings restored to their original configurations.

Test Measurements

The field test evaluation will involve periodic measurement of flue gas emission concentrations and continuous event monitoring of cyclical operations. The primary objective of the test will be to observe the long term pollutant emissions characteristics of the integrated furnace design. A secondary objective is to establish the overall season-averaged thermal efficiency of the furnace so that the pollutant emissions results can be evaluated in light of the present concerns for energy conservation.

Air Pollutant Emissions. The long-term monitoring of flue gas pollutant emission concentrations will be conducted with measurements at monthly intervals. The pollutants to be measured are: nitric oxide (NO) and total oxides of nitrogen (NO_x) by chemiluminescence; carbon monoxide (CO) by nondispersive infrared; unburned hydrocarbons (UHC) by flame ionization and smoke by the Bacharach method. In addition, carbon dioxide (CO_2) by NDIR and thermal conductivity, and oxygen (O_2) by polarography will be measured to determine the operating conditions by stoichiometry. All of the instruments, with the exception of smoke pumps, will be installed into and operated from a 3/4-ton capacity van mobile laboratory. The van will transport the instruments to each home site and a 0.0064-meter (0.25-inch) diameter FEP Teflon line will be connected to the flue at a point near the furnace to conduct the flue gases to the analyzers. The control of the furnace will then be locked into a 4-minute-on/8-minute-off operating cycle by a repeat cycle timing device. Sample transport pumps within the van will draw samples continuously and the gases will be analyzed throughout the 4 minute firing cycle. CO and UHC concentrations characteristically "spike" on startup, and therefore, the concentration profiles for these species will be recorded on continuous drive paper charts. These pollutant emissions will then be averaged over the 4-minute firing and compared from month to month in terms of their cycle-averaged values. The integrated furnace has consistently operated in the laboratory at SR = 1.20, smoke <No. 1 Bacharach, CO < 1.0 g/kg, UHC < 0.1 g/kg and NO ≈ 0.7 g/kg. It is expected that all six field test units will perform close to these values, and determining whether these low pollutant emission levels can be maintained throughout the heating season is a primary objective of the field test effort.

Thermal Efficiency. Steady-state thermal efficiency of a furnace unit is normally estimated in terms of the heat rejected out the flue during a continuous firing. This involves simply measuring the net temperature and the composition of the flue gases (see Fig. 4).

However, the accurate measurement of the cyclic operation thermal efficiency is complicated greatly by heat sinking of components, the need to measure very low pressure drop flows, relatively inconsistent furnace controls (e.g., bimetallic spring fan control), and nonuniform flow conditions. Each of these factors introduces variables that result in considerable data scatter. The measurement of season-averaged thermal efficiency is further complicated by variable cycle timing. For these reasons, substantial season-averaged thermal efficiency values have not been reported, instead, estimates have more often been reported. The influences of the many variables mandate statistical analysis techniques for evaluating season-averaged thermal efficiency. Therefore, continuously monitoring, automatic data acquisition methods were devised to record a large number of data points for a valid statistical analysis.

A data logging system with a programmable central controller will be used on one furnace to monitor all the temperature and flow parameters once every second and data from each firing will be stored on magnetic tape. This system will result in cycle-averaged thermal efficiency data that is correlated to cycle timing parameters and, eventually will be used to evaluate season-average performance. For this reason, cycle timing will be carefully monitored on the remaining five furnaces by automatic time recording data loggers and these data will also be stored on magnetic tape. All the stored information will be retrieved and evaluated monthly. The data from the primary programmable data logger will be reduced on-site by the central controller while the cycle timing data cassettes will be transported back to the Rocketdyne facility for reduction on a timesharing computer system.

The steady-state thermal efficiency of the integrated furnace at 0.79 ml/s (0.75 gph) firing rate is 85%, which is about the maximum achievable for non-condensing flue gas furnace systems. The cycle-average efficiency in actual homes is expected to be approximately 5% lower at about 80%. The season-average efficiency for the integrated furnace will be determined by the field test. In addition, the fuel conservation effects of the sealed air system, which does not appear in the above heat transfer evaluations, will be determined by comparison of the fuel consumption of the two previous seasons and that of the field test season. Overall reductions in fuel consumption resulting from the installation of the integrated furnace are expected to be well over 10%.

CONCLUSION

Specific criteria for optimizing the designs of burners and combustion chambers for residential oil-fueled space heating systems with respect to pollutant emissions and thermal efficiency have been presented earlier (Ref. 1 through 4). Developed for laboratory testing of commercial and research burners in a variety of research combustion chambers, those criteria are believed to be applicable to many types of residential heating equipment, e.g., either warm-air furnaces or hydronic boilers with either side-fired or tunnel-fired combustors. They are sufficiently general that any manufacturer might, in principle, utilize them to create his own embodiment of a low-emission, improved efficiency space heating unit which is compatible with his own existing design concepts and manufacturing techniques. However, until the criteria's applicability and advantages have been demonstrated clearly, it is deemed unlikely that the industry will give them serious consideration.

The integrated residential furnace and field verification activities described herein are intended to serve as proof-of-concept demonstrators. Within the scope of this program, only one specific embodiment of the design criteria could be carried through the entire process from design concept to field verification testing. Therefore, the integrated furnace was intentionally made to conform to the most prevalent heating system type: a warm-air furnace with a side-fired firebox. It is anticipated that the field test results will document substantial reductions in emissions and gains in performance for the integrated furnace and that these will encourage manufacturers to consider applying the underlying criteria to their products. At that point, it will be important to remember that the integrated furnace is only one of many unit designs which might be conceived as satisfying the several design criteria. (In fact, it is indicated in Ref. 1 and 2 that preferred configurations would embody tunnel-fired and/or water-cooled combustors.)

Application of the low-emission design criteria to a different basic type presumably would entail an R&D program with scope and magnitude at least comparable with that described herein for the integrated furnace demonstrator. This would provide both confirmation that the general criteria are indeed applicable and an opportunity to respond empirically to unusual experimental results, such as the downgrading of the integrated furnace's firing rate to eliminate its excessively smoky operating condition. That particular problem, which arose from undetected errors in the smoke measurements sometime during the prototype furnace testing period (i.e., after establishment of the general design criteria), is perhaps an extreme example of empirical adjustment that might be required.

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TABLE I. COMPARISON OF POLLUTANT EMISSIONS FROM VARIOUS RESIDENTIAL FURNACES

	TUNED AVERAGES FROM REF. 7	ORIGINAL STOCK FURNACE	PROTOTYPE FURNACE
STOICHIOMETRIC RATIO	1.85	1.50	1.15
CARBON MONOXIDE, g/kg FUEL	0.6	0.27	0.55
UNBURNED HYDROCARBONS, g/kg FUEL	0.07	0.015	0.055
SMOKE, BACHARACH NUMBER	1.3	0	<1
NITRIC OXIDE, g/kg FUEL	1.8	2.2	0.83

TABLE II. PERTINENT HOUSING CHARACTERISTICS FOR ELEVEN CANDIDATE CITIES

CANDIDATE CITY	SEPT. THRU MAY DEGREE DAYS (°F DAYS)	THOUSANDS OF HOUSING UNITS	WITH WARM AIR FURNACE	HEATING USE FUEL OIL	WITH BASEMENT	COMMENT
BOSTON	5300	881	20%	69%	94%	ATLANTIC MARITIME CLIMATE
PROVIDENCE	5626	281	82%	58%	94%	
HARTFORD	6314	218	77%	68%	28%	
CHICAGO	6093	2,281	66%	12%	83%	GREAT LAKES MARITIME CLIMATE
TOLEDO	6110	180	88%	12%	83%	
CLEVELAND	6088	675	71%	9%	84%	
INDIANAPOLIS	5001	388	78%	11%	53%	CONTINENTAL CLIMATE
SCRANTON	6097	78	11%	48%	88%	
COLUMBUS	5001	288	81%	9%	77%	
PITTSBURGH	5401	780	88%	5%	87%	
ALBANY	6610	98	25%	44%	88%	

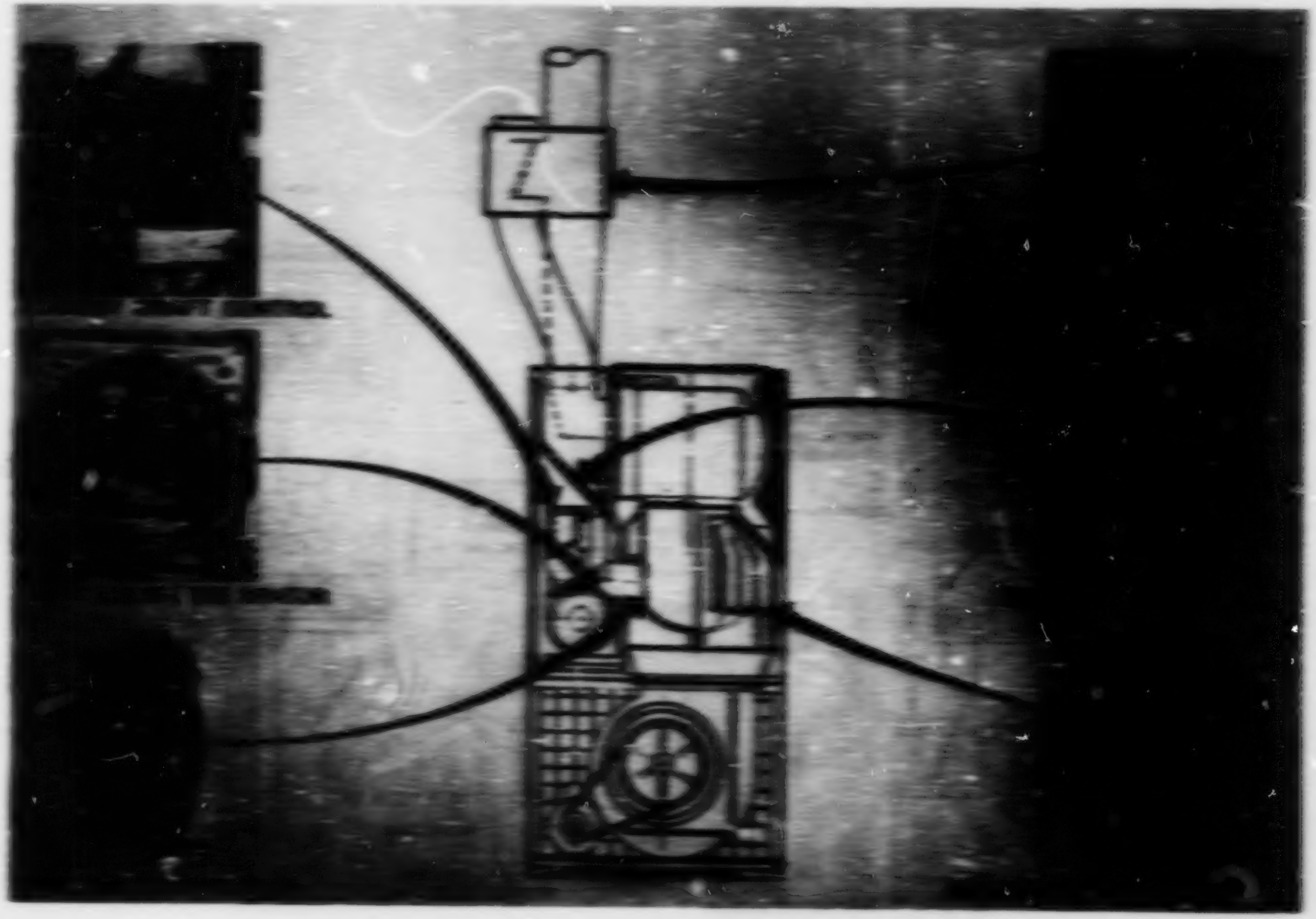

Figure 1. Prototype Furnace Modified Components

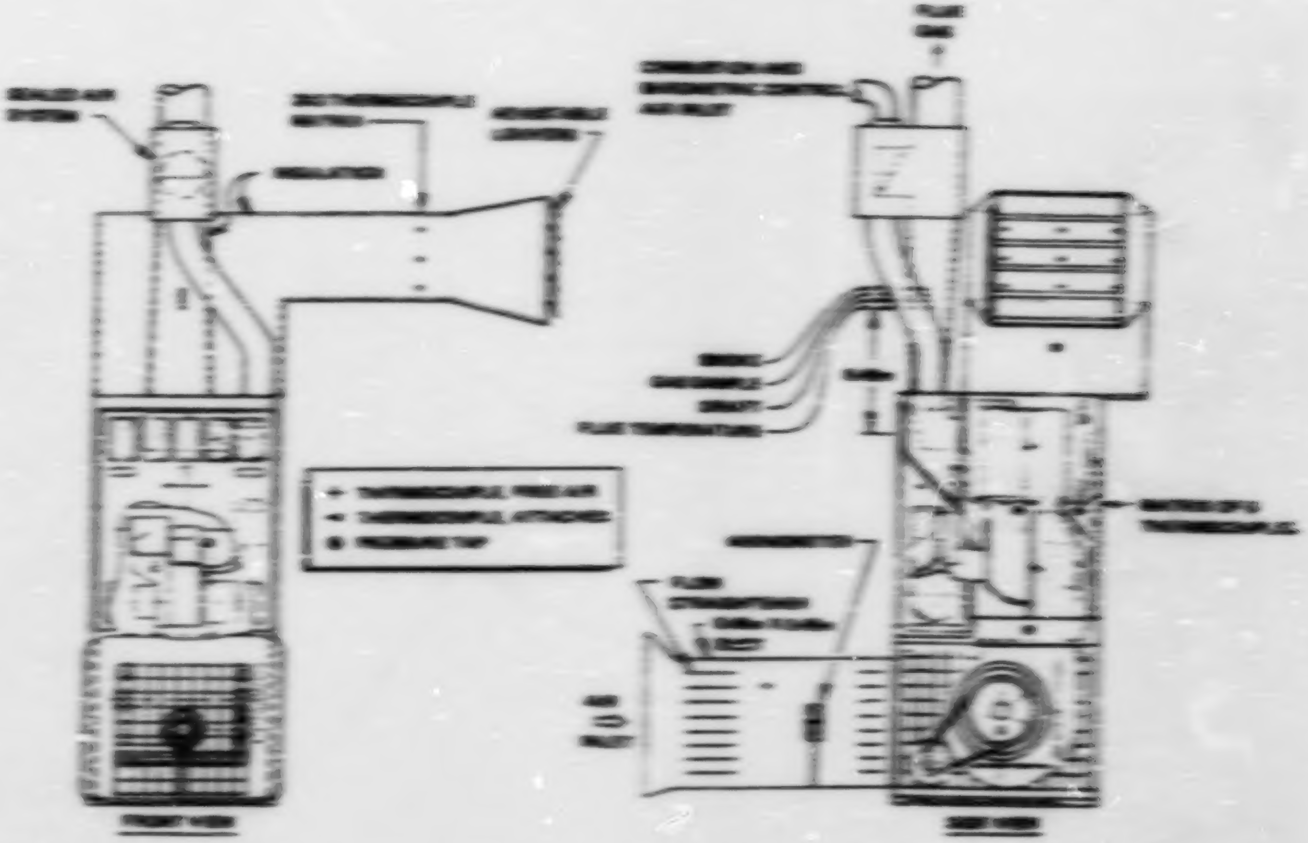

Figure 2. Schematic of the Furnace Performance Evaluation System

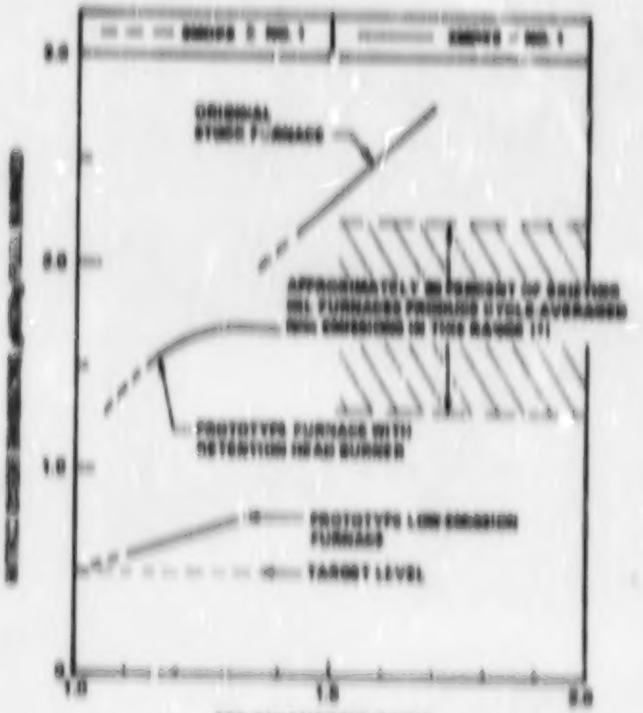

Figure 3. Cycle-Averaged NO Emissions

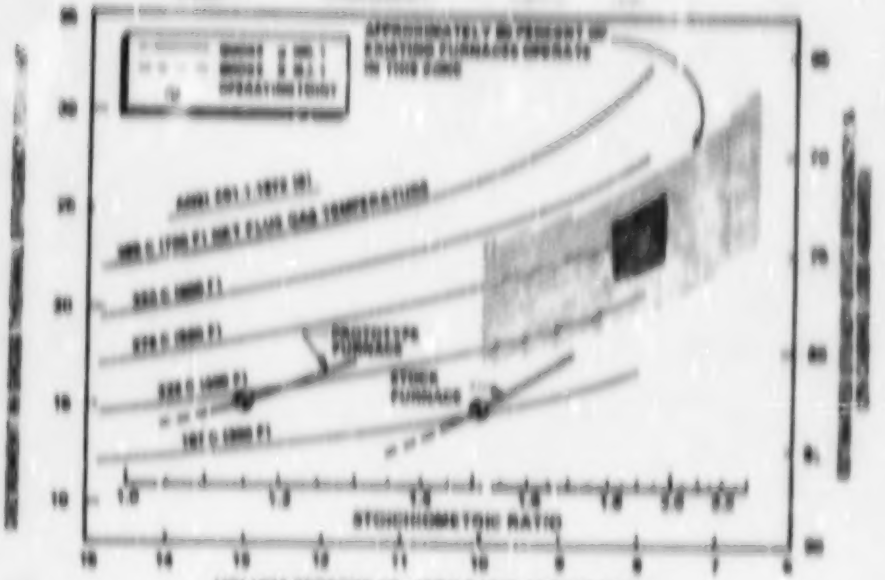

Figure 4. Pseudo-Steady-State Thermal Efficiencies

Figure 5. Optimum Low-Emission Oil Burner

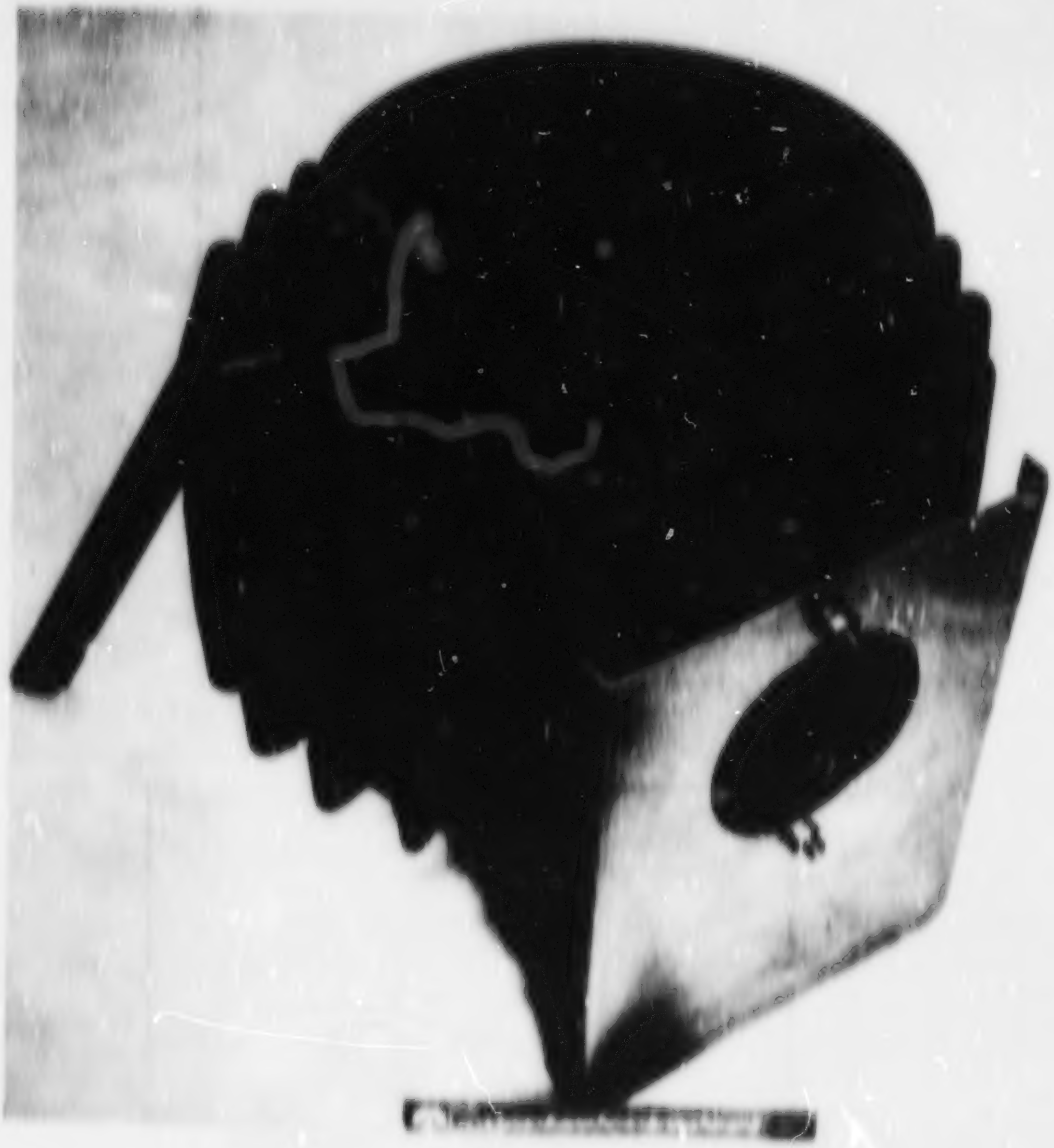

Figure 6. Cast-Formed Air-Cooled Combustion Chamber

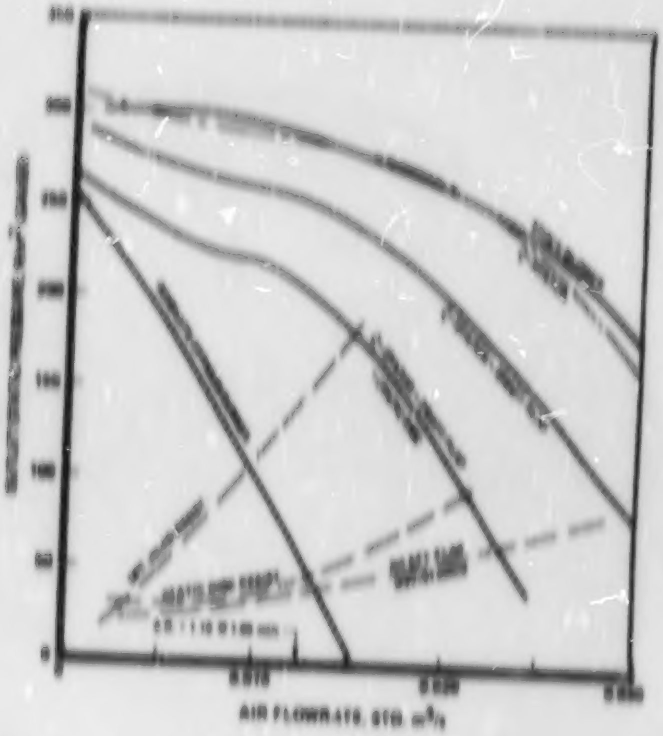

Figure 7. Throttled Exit Air Flow Characteristics

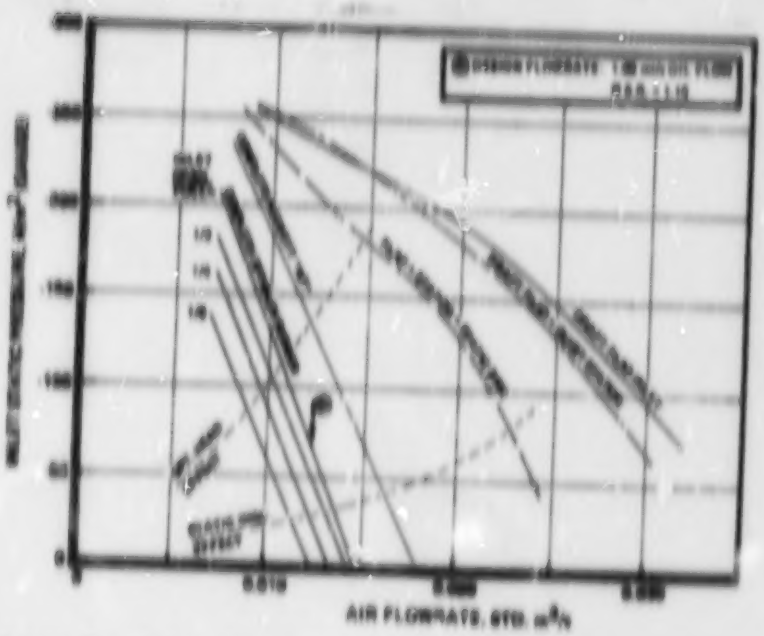

Figure 8. Inlet Throttling Air Flow Characteristics

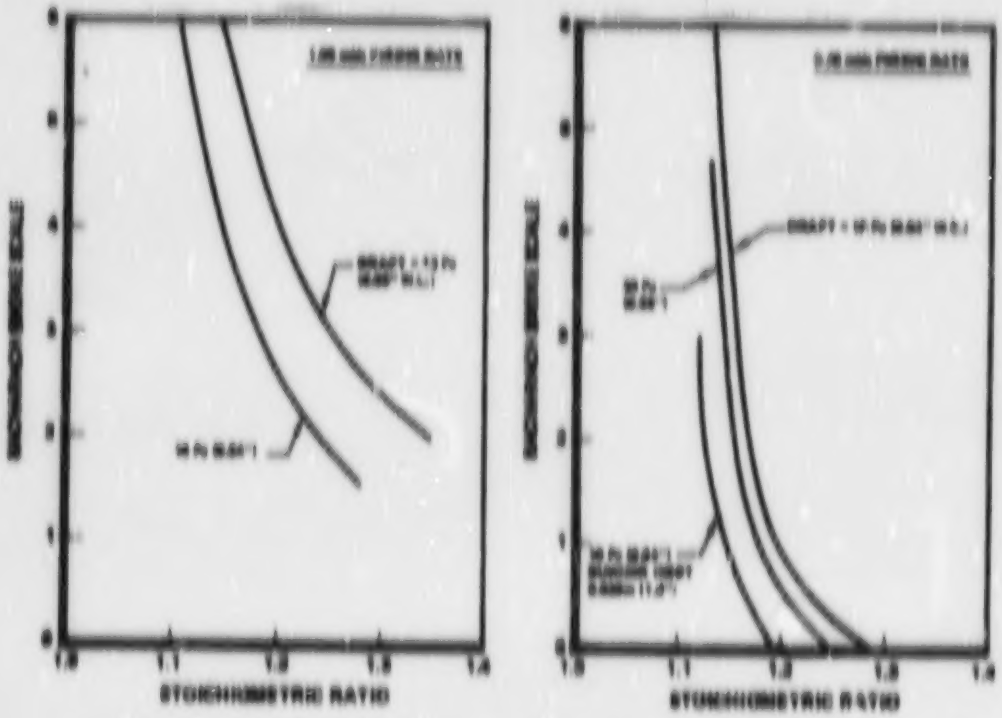

Figure 9. Integrated Furnace Smoke Emission Characteristics

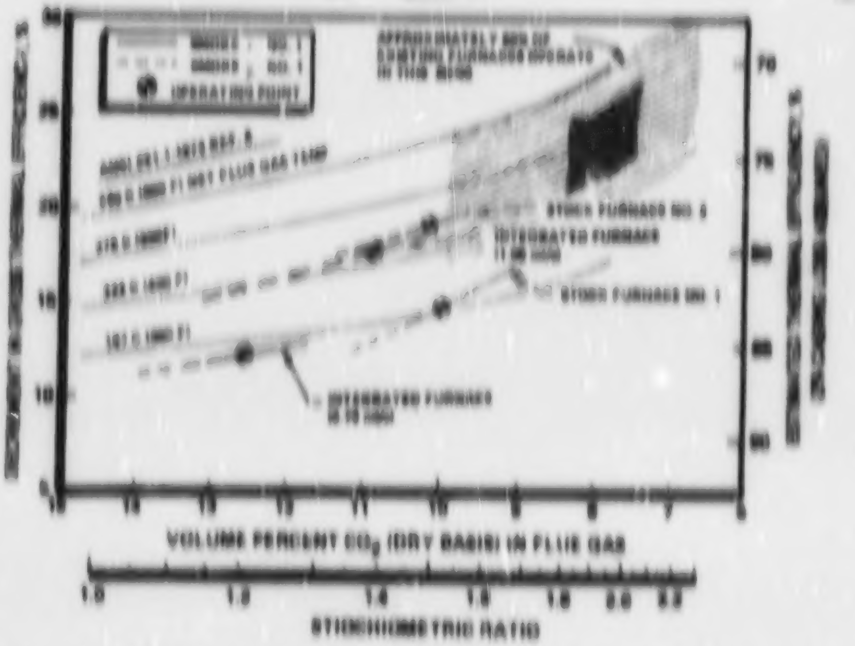

Figure 10. Thermal Efficiencies of the Integrated and the Stock Furnaces

PERFORMANCE OF A THERMAL AEROSOL OIL BURNER

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ABSTRACT

Recent research has shown the detrimental effect of excess oil burner capacity on seasonal efficiency of residential heating systems. A thermally generated aerosol offered the promise of reduced firing rate and superior atomization wihout the need for extremely small burner nozzle orifices. Thus the objective of this study was to determine the relationship between fuel temperature and pressure for a clean burning, efficient, small oil burner.

The results showed that clean, efficient combustion can be achieved at a firing rate of about 0.42 cm^3/s (0.4 gph) with a thermal aerosol burner. Lower pressure -- (about 200 kPa g (29 psig)) and heated fuel (about 150°C) reduced nozzle capacity 60 percent and improved atomization. An experimental burner is described in which heated fuel flashing in the nozzle produces a mixture of vapor and fine droplets. Provision was made for independent control of atomizing pressure, fuel temperature, and flowrate.

Data are presented on the effects fuel temperature, fuel pressure and excess air on emission of hydrocarbons, carbon monoxide, soot and oxides of nitrogen for both No. 1 and No. 2 fuel oil. Clean efficient combustion was achieved with low excess air. Increased excess air was needed in the research burner to reduce NO_x. Fuel temperature was limited by its tendency to precipitate carbon. Regions of reduced fuel pressure with elevated temperature are defined which yield reduced firing rate, efficient combustion and low emissions.

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INTRODUCTION

Recent studies (1,2,3) have shown that excess capacity in residential heating systems leads to excessive stack losses and reduced seasonal system efficiency. A study of 26 oil burners in the Boston area (4) revealed an average excess capacity of 147% (i.e. 247% of design load). The capacity of these burners was then reduced an average of 27.1% by installing smaller nozzles. It was found, however, that excess air had to be increased an average of 36.9% to prevent smoke. The increased losses associated with increased excess air largely cancelled the improvement to be expected from reduced capacity.

Many conventional oil burners are too large to heat a residence efficiently. Greater use of insulation compounds the oversize problem. There appears to be a real need for a burner with a capacity of 0.4 to 0.5 gph (0.42 to 0.53 cm^3/s). Pressure atomizing nozzles of this size have such small orifices and passages that they are prone to becoming plugged after unacceptably short operating times.

It is well known that improved atomization, i.e., smaller drops, permits better mixing of the air and fuel and reduces the tendency to form soot. It would appear, therefore, that a burner that should achieve good atomization without resorting to very small orifices in the nozzle for a flow rate of about 0.4 cm^3/s should give better efficiency in residential heating applications.

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A droplet of fluid is held together by surface tension. The surface to volume ratio increases when a given volume of fluid is divided into a larger number of smaller drops. Energy input is needed to overcome the surface tension force when the surface area is increased. It can be shown that the radius of a drop is given by (see Appendix)

$$r = \frac{\sigma 3}{\Delta E}V \qquad (6)$$

where: σ = surface tension
E = energy input
V = fluid volume

Equation (6) gives the average drop size consistent with energy consideration. Any spray, however, will have drops with a wide range of sizes. Thus while it may not be possible to compute actual drop size from equation (6), it does show the benefits of heated fuel. Heating the fuel both reduces the surface tension and increases the energy content.

W. Tenney patented a "Fuel Aerosolization Apparatus" based on a thermal principle (5). In this device fuel oil under pressure is heated and then allowed to expand through a nozzle. The hot oil flashes to a vapor as the pressure drops in passing through the nozzle. Upon cooling, the vapor condenses into very small (less than 1 micrometer) drops which produce a dense white smoke. The U.S. Navy used this device to produce smoke screens in World War II. This paper presents test results on a residential size oil burner using this means of atomizing fuel oil.

The objective of this study was to show that a thermal aerosol generator could be used as an oil burner with a capacity of about 0.4 cm^3/s (0.39 gph) and to define the operating parameters needed for clean, efficient combustion.

EXPERIMENTAL PROCEDURES

APPROACH

The approach was to design a burner that would permit separate control of each of the operating variables. These were fuel temperature, fuel pressure, fuel flow rate and air flow rate. Since fuel flow is a function of both fuel pressure and temperature, some form of variable area nozzle was needed to permit independent control of fuel flow rate. Three standard oil burner nozzles rated at 0.85, 1.0 and 1.25 gph were used. The highest fuel pressures of interest was used with the small nozzle and the lower pressures with the large nozzle. Thus it was possible to stay within the flow range of interest while exploring temperature and pressure effects.

Combustion efficiency was computed from measurement of the oxygen content and temperature of the flue gases. The heat exchanger coupled to the combustion chamber was not designed for efficient energy absorption but rather to simulate the temperature quenching that normally occurs. Therefore, efficiency calculations are based on an assumed flue gas temperature rise of 300°C (540°F).

The flue gas analysis was made with instruments discussed under the section on instrumentation

Burner Design

The burner consisted of a steel pipe 178 mm (7 in.) i.d. by 508 mm (20 in.) long. The first half was insulated with 13 mm (0.5 in.) thick moldable ceramic fiber insulation.* The remainder of the chamber including the inlet end was insulated with 6 mm (0.25 in.) of the same material. These dimensions gave a volumetric heat release rate of 1,920 kJ/s-m^3 (186,000 BTU/hr-ft^3) which was consistent with standard practice.

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*WRP Ceramic fiber insulation, Refractory Products Co., 12 W. Main st. P.O. Box 309, Carpentersville, IL 60110.

The nozzle was screwed into a fitting attached to the fuel valve. The nozzle in turn sprayed fuel into a vortex mixing chamber attached to the end of the combustion chamger. This vortex chamber was 76 mm (3 in.) dia. by 25 mm (1 in.) long. A 38 mm (1.5 in.) orifice separated the vortex chamber from the combustion chamber.

Air was admitted tangentially to the vortex chamber through four 13 mm (0.5 in.) steel tubes spaced 90^0 apart around the vortex mixing chamber. Four additional air tubes were also installed parallel to the burner axis. Use of these tubes provided air flow with no swirl. The air was supplied through a single orifice meter to a header. The layout of the combustion chamber is shown in Fig. 1.

Fuel Handling System

Fuel was supplied from a weigh tank mounted in a pressurized chamber. The weigh tank was mounted on a cantilevered beam equipped with strain gauges. The chamber was pressurized with compressed nitrogen which supplied the atomizing pressure. Fuel flow rate was determined by observing the change in weight of the weigh tank over a measured time interval. The weigh tank had a capacity of 700 cm^3 which gave a running time of 20 to 30 minutes before refueling was needed.

The fuel was piped from the weigh tank chamber to the electric powered heater located directly above the weigh tank. This was a 1000 watt heater mounted in a section of 1.5 in. pipe. The high powered heater was needed to keep the heat flux density at the heater surface to the recommended level of 9 watt/in.^{2}. The fuel valve and burner nozzle were mounted directly on top of the fuel heater. Layout of the fuel measuring and heating system are shown in Fig. 2.

Instrumentation

The instrumentation layout is shown in Fig. 3. Instruments used were as follows:

Strain Gauge on Fuel Weigh Tank - Baldwin Lima Hamilton SR4 Strain Indicator, Type N.

Oxygen Measurement - Westinghouse, Hagan Oxygen Monitor.

Nitrogen Oxides - Aero Chem Chemiluminescence Monitor for NO, NO_x.

Hydrocarbons - Beckman Model 400 Hydrocarbon Analyzer.

Carbon Monoxide, Carbon Dioxide, Methane - Honeywell Non-dispersive Infrared Analyzer.

Particle Size Measurements - Thermo Systems Inc. Model 3030 Electrical Aerosol Size Analyzer for 0.01 to 1.0 micrometer range and ROYCO Particle Analyzer for the 0.5 to 10 micrometer range.

Fuel Temperature - Copper vs Constantan thermocouple and Honeywell Class 19 Recorder.

Fuel Pressure - Heise precision pressure gauge, 0-50 PSI range.

Air Flow - 0.5 in. dia. orifice and water filled "U" tube manometer.

Smoke Measurements - Bacharach Smoke Tester.

TEST PROCEDURE

The test procedure was to fill the fuel weigh tank with No. 1 or No. 2 oil. Properties of the fuel oil are presented in Table I.

The desired pressure on the fuel would be set. The fuel valve was opened slightly to bleed air from the system and fill the fuel heater. The valve was then closed and power to the heater was adjusted to give the desired fuel temperature in the heater. Since the nozzle tended to pick up considerable heat from the flame, it was necessary to compensate for this in adjusting the fuel heater temperature. When the desired temperature was reached, the air supply was turned on, fuel was turned on and ignited with a propane torch. After about 2 or 3 minutes the burner insulation was hot and the flame was stabilized. The air flow was then adjusted to give the desired flue oxygen level. The various instruments were then read. Following this the air flow or fuel pressure was adjusted to a new value and a new set of readings was taken. Usually about four sets of readings were taken before it was necessary to refuel.

The large number of permutations of the variables made it impractical to test all possible combinations. Instead operating parameters were selected to cover a wide operating range and additional detail when results of special interest were observed. Tables II and III show the combinations of firing conditions studied. A brief test of the effect of swirl and a transient test were carried out in addition to the steady state tests.

RESULTS AND DISCUSSION

The experimental results are presented in Figures 4 through 17 and Tables IV and V.

AEROSOL SIZE DISTRIBUTION

Figure 4 shows how the aerosol drop size distribution is affected by fuel temperature and pressure. Figure 5 shows the relative volume distribution as a function of drop size. Fuel temperature of 200°C and above produced substantial numbers of drops in the 0.1 micrometer range. However the fuel temperature had to be 250°C or higher to produce a large volume concentration.

The data in Figure 5 cannot be used to estimate air/fuel ratio because the measurements ignore droplets bigger than about 5 micrometers. The larger droplets tended to settle on the walls of the sampling tube and sample chamber. While the number of larger drops was small compared with smaller drops, the mass of fluid in the larger drops probably was substantially greater. Figure 5 is useful for comparing the relative volume of fuel in the 0.03 to 3.0 micrometer range.

As expected, increased pressure and lighter weight (NO. 1) fuel increased the number of small drops. When converted to a volume or mass distribution the distribution peaks at around 3 micrometers. The apparent discontinuity at around 1.0 micrometers was at least partially due to the use of two different measuring instruments. A Thermo-Systems Inc. model 3030 Electrical Aerosol Size Analyzer was used in the range 0.01 to 1.0 micrometers. This instrument based on a measurement of the charged particle current carried by the collected particles after they have been charged. A ROYCO Particle Analyzer was used to measure the concentration of drops in a 0.5 to 1.0 micrometer range. This instrument is based on an optical principle.

These instruments required a sample of the fuel spray to be fed into a separate sampling chamber. An aerosol sample was then fed into the instrument from this chamber. Only the smaller air-borne drops would stay in suspension through this sampling system. Hence the larger drops in the fuel spray were ignored.

FIRING RATE

Figures 6 through 11 show the effect of fuel temperature and pressure on flow for each of the three nozzles and each fuel. Our objective was to explore conditions in the flow range around 0.42 cm^3/s (0.4 gph). To do this the pressure range was lowered from 207 to 345 kPa (30-50 psi) with the .85 gph nozzle to 103-207 kPa (15-30 psi) with 1.25 gph nozzle. Fuel pressure was very stable and was controlled by the regulated nitrogen pressure in the fuel chamber.

Fuel flow measurements were made with the burner operating. The nozzle picked up considerable heat from the flame. Consequently the nozzle temperature was substantially higher than the fuel heater temperature. The nozzle temperature was measured at the fitting into which the nozzle was screwed. The nozzle orifice temperature probably was a few degrees higher. Because of these complications the nozzle temperature and therefore the fuel temperature varied somewhat as a function of flow rate. We endeavored to compensate for this but a 10^0C uncertainty in the temperature of fuel entering the nozzle probably occurred. Since we were looking for the effect of a 100^0C or higher fuel temperature change, the uncertainty was not serious.

The flow decreased with decreasing pressure as expected. We expected flow to increase slightly with increasing temperature due to lower viscosity. When the boiling range was reached the flow was expected to decrease rapidly due to vapor formation in the nozzle orifice. However, in all cases except that with NO. 1 oil in the 0.85 gph nozzle, flow decreased with increasing temperature. We believe this was due to the fact that fuel oil boils over a rather wide temperature range. The light ends probably produce some small bubbles in the nozzle orifice at fuel temperatures as low as 100^0C. The restriction produced by bubble formation increases with increasing fuel temperature.

The one case where the 0.85 gph nozzle was operated at 205-215°C and 276 kPa (40 psi) with No. 1 oil (Fig. 6) did show a substantial flow restriction. The No. 1 oil probably produced a substantial amount of vapor under these conditions. No. 2 oil (Fig. 10) did not show any break, but probably would have shown a break in the curve at some higher temperature.

In general we found we could operate reliably at 150°C and lower, but cokeing become a problem during shut down at higher fuel temperatures. Apparently, when the fuel was shut off, heat from the combustion chamber raised the nozzle temperature even higher than its operating temperature.

The 1.0 gph nozzle seemed to operate with a characteristic different from the other nozzles. The curvature of the flow curve was opposite from that of the other two nozzles. This shows more clearly in Figure 9 where the three nozzles are compared. The curves have about the right relationship in the 50-75°C range but the 1.0 gph nozzle curve drops much lower at temperatures above 125°C. Only one set of data were taken for the 1.0 gph nozzle. It is quire possible the nozzle was partially restricted by carbon particles generated in the fuel heater.

Figure 10 shows the flow curve for the 0.85 gph nozzle with No. 2 oil. More data were taken with this combination than the others. The breakdown point in the flow curve caused by boiling in the nozzle occurred at about 250°C. However, at that temperature there were problems of nozzle fouling due to cokeing.

EFFICIENCY

Combustion efficiency was calculated from flue oxygen concentration and an assumed flue temperature rise. The actual flue temperature rise in any real furnace would be a function of heat exchanger design. For any given set of combustion conditions a heat exchanger could be designed to achieve the assumed flue temperature rise. A flue temperature rise of 300°C (540°F) is commonly found.

Figure 12 presents a correlation among flue oxygen, flue carbon dioxide and excess air for the two fuels studied. A 0°C (32°F) dew point was used in preparing Figure 12 since we used an ice bath water trap to remove moisture from the flue sample.

Figure 13 gives the gross steady state efficiency (based on higher heating value of fuel) as a function of flue temperature and oxygen content.

Swirl in combustion chambers has been defined by different authors in somewhat different ways (6, 7). We have used a simplified form of Beer's definition which is derived in the appendix. The swirl parameter so defined for this combustion chamber was 4.5. This would be equivalent to a swirl number of about 2.3 for the dimensions of this combustion.

The swirl produced clean combustion under almost all firing conditions. It was feasible, therefore, to assume a burner of this type could be operated at 2% flue oxygen (10% excess air). This would give a steady state efficiency of slightly over 81% with a 300°C flue temperature rise.

EMISSIONS

Nitrogen Oxides

Figures 14 and 15 show the effect of operating parameters on nitrogen oxide. The nitrogen oxides were found to be essentially all in the form of nitrous oxide, NO, but are reported as NO_x. Both NO and NO_x were measured. The concentrations were always the same.

As expected, NO_x increased as the flue oxygen decreased due to the higher flame temperature associated with more nearly stoichiometric mixtures. The NO_x level at a given flue oxygen decreased as the fuel temperature increased. In most, but not all, cases the NO_x also decreased with increasing atomization pressure. Improved atomization generally reduced NO_x levels. This is consistent with measurements and calculations (6, 8) which show that increased swirl tends to reduce NO_x. The explanation is that improved mixing reduces flame volume and therefore residence time. This is, of course, offset by higher flame temperatures.

The fuel nitrogen was measured as shown in Table I. If this is all converted to NO_x, the contribution of fuel nitrogen to the NO_x concentration is given in Table IV.

Figures 14 and 15 show that at 8% flue oxygen the NO_x all can be attributed to fuel nitrogen. However, at lower flue oxygen levels, some of the NO_x must come from atmospheric nitrogen.

Unburned Fuel

Smoke, total hydrocarbons and carbon monoxide were undetectable for all firing conditions except flue oxygen levels well below 1%. Apparently, the high degree of swirl dominated other effects.

TRANSIENT PERFORMANCE

Some smoke, hydrocarbons, carbon monoxide and even methane were usually observed right after ignition. It seemed that these disappeared more quickly when hot fuel was used. Although the instrumentation was not well suited to transient measurements, one transient experiment was conducted. The 0.85 gph nozzle was used with No. 2 oil at a pressure of 345 kPa (50 psi). Two runs were made; the first was with unheated oil and the second was with oil heated to yield a 150°C nozzle temperature. The results are presented in Table V.

After 1.5 minutes of operation the unheated oil gave a smoke No. 5 whereas the heated oil was already down to zero smoke. The nozzle with unheated oil had already risen to 80°C in 1.5 minutes whereas the nozzle temperature with heated oil was at 121°C in 1.5 minutes. Within 5 minutes both tests were down to 0-1 smoke. The flue oxygen was about 3% for the unheated oil case whereas it was about 5% with heated oil. This difference in flue oxygen had no effect during steady state runs since smoke was unmeasurable unless flue oxygen was reduced well below 1%. For some unexplained reason, smoke increased again after 15 to 20 minutes. This phenomenon was not observed in any other tests.

The NO_x level was higher with unheated oil. The increase was undoubtedly due to the lower flue oxygen.

While this test was not conclusive, it supported the qualitative observation that heated fuel produced a shorter transient. Better data would require faster sampling, less instrument delay and continous recording.

EFFECT OF SWIRL

The high swirl seemed to mask any effect of improved atomization with hot fuel. We therefore modified the burner to eliminate swirl. The objective was to try and answer the original hypothesis that improved atomization achieved through the use of hot fuel would reduce emissions and improve efficiency. Four additional air tubes were installed in the end of the mixing chamber to admit air parallel to the fuel jet axis. The tangential air jets were plugged. The results of a comparison using No. 1 oil and the 1 gph nozzle are presented in Table VI. When the swirl was eliminated there was a correlation between smoke and fuel temperature. A nozzle fuel temperature of 114°C produced No. 9 smoke, 118 ppm CO, 5 ppm CH_4, 31 ppm hydrocarbons and 11 ppm NO_x even with a flue oxygen of 4.9%. Increasing the fuel temperature to 179°C with the same flue oxygen lowered all emissions except NO_x. Increasing the fuel temperature to 190°C and lowering flue oxygen to 4.1% increased the smoke slightly but lowered the other emissions further. All emissions except NO_x disappeared when swirl was restored even though fuel temperature was varied from 121 to 178°C and flue oxygen was varied from 8.1 to 2.1%. The NO_x levels were consistent with previous measurements.

With swirl present the flame was very compact and nonluminous. Eliminating swirl produced a much larger volume luminous flame. The pictures in Figures 16 and 17 show this difference.

The total pressure of the air supplied when operating at 0.42 cm^3/s (0.4 gph) and 2% flue oxygen was about 1.2 kPa (5 in. water). This undoubtedly could be reduced by increasing the area of the air inlet passages and by reducing the swirl parameter to perhaps 2. Swirl does, however, add to the pressure requirement of the blower.

CONCLUSIONS

The use of heated fuel oil to produce a thermal aerosol makes possible the atomization of fuel oil at lower pressures and reduced firing rates. Heating the fuel oil, both No. 1 and No. 2, to 150^{0}C greatly increases the number of droplets in the 0.1 micrometer range.

The formation of bubbles as fuel flows through the swirl passages in the nozzle restricts flow. This permitted standard 0.85 gph to 1.25 gph hollow cone spray nozzles to be fired at only 0.42 cm^3/s (0.4 gph). Atomization achieved in this manner reduced soot, hydrocarbons and carbon monoxide.

When combined with air swirl (swirl parameter as defined with appendix equal to 4.5), non-luminous flames were achieved at flue oxygen levels of 2.0% (10% excess air). The Bacharach smoke was zero and there were no measurable hydrocarbons or carbon monoxide. Luminous flames were present without swirl but the thermal aerosol was beneficial in reducing emissions.

The thermal aerosol combined with swirl reduced NO$_x$ formation in most cases. This effect tends to disappear when the flue oxygen is reduced below 2% (10% excess air).

The use of heated fuel improves combustion during burner start up. Fuel heated to 150^{0}C achieved zero smoke in less than 1.5 minutes. Fuel at 80^{0}C produced a No. 5 smoke at 1.5 minutes but achieved a zero smoke within 5 minutes.

The flow rate of 1.0 gph nozzle was varied from 0.2 to 0.6 cm^3/s by varying fuel temperature. Clean combustion with low excess oxygen was achieved at all firing rates.

Thus the combination of the thermal aerosol generator with substantial air swirl gives a non-luminous flame with low emissions at a flue oxygen level of 2%. If the flue temperature rise is held to 300^{0}C this results in 81% combustion efficiency.

RECOMMENDATIONS

The results of these experiments show promise for a residential oil burner of 0.4 to 0.5 gph rated capacity. A prototype burner of this size should be built. The burner should have a blower with sufficient pressure rise to supply the vortex mixing chamber. Provision would be made for regeneratively heating the fuel. A small electric powered heater should be provided for initial heating of the fuel. Excess air should be held in the 5 to 10% range. Recirculation should be investigated as a means of further reducing NO_x.

APPENDIX

Drop Size

Surface tension is defined as the work required to displace a unit area of fluid surface.

$$\sigma = WK/A \qquad (1)$$

For a spherical droplet,

$$WK = \sigma A = \sigma 4\pi r^2 \qquad (2)$$

The volume of the droplet is,

$$V = (4/3)\,\pi r^3 \qquad (3)$$

And the work per unit volume is,

$$WK/V = \frac{\sigma 4\pi r^2}{(4/3)\pi r^3} = \frac{3\sigma}{r} \qquad (4)$$

Thus the radius of the drop should be,

$$r = \frac{3\sigma}{WK/V} \qquad (5)$$

Since work equals the change in energy,

$$r = \frac{3\sigma}{\Delta E/V} \qquad (6)$$

Swirl Parameter

The swirl parameter is defined as the ratio of tangential velocity to axial velocity at the combustion chamber mixing orifice.

$$N_s = \frac{V_t}{V_a} \qquad (7)$$

Air enters the vortex chamber tangential to the axis and at a radial distance, r_i. The air is accelerated due to the conservation of angular momentum as it goes through the mixing orifice which has a radius, r_o. Thus the tangential velocity at the orifice is:

$$V_t = \frac{Q}{A_i}\frac{r_i}{r_o} \tag{8}$$

where: Q = air flow rate

A_i = area of air inlet tubes

r_i = radial distance of tubes from axis

r_o = radius of orifice

The axial velocity, V_a is

$$V_a = \frac{Q}{\pi r_o^2} \tag{9}$$

Then

$$N_s = \frac{Q\, r_i}{A_i\, r_o} \cdot \frac{\pi r_o^2}{Q} \tag{10}$$

For the four air inlet tubes

$$A_i = 4\pi r_i^2$$

$$N_s = \frac{r_i\, r_o}{4 r_i^2} \tag{11}$$

r_i = 1.5 in.

r_o = .75 in.

r_i = .25 in.

$$N_s = \frac{(1.5)\,(.75)}{4(.25)^2} = 4.5 \tag{12}$$

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TABLE I. FUEL PROPERTIES
(Measured by Twin City Testing Laboratory)

Property	Value No. 1 Oil	 No. 2 Oil
API Gravity, 15.6^{0}C (60^{0}F)	42.0	34.8
Heating Value		
(J/m^{3})	538,862	545,661
(BTU/gal)	134,924	136,627
Carbon (%)	86.26	87.15
Hydrogen (%)	13.58	12.68
C/H	6.35	6.87
Sulfur (%)	0.19	0.37
Nitrogen (%)	0.0064	0.012
Nickel, ppm	26	32
Vanadium, ppm	23	24
Lead, ppm	28	42
BTU/lb	--	--
Atomic H/C	--	--

TABLE II. FIRING CONDITIONS FOR NO. 1 FUEL OIL

Nozzle (GPH)	Fuel Temp °C	Fuel Pressure kPa gage	Excess Oxygen %
0.85	20	207	2,4,8
	20	276	2,4,8
	20	345	<1,2,4,8
	150	207	2,4,8
	150	276	2,4,8
1.00	20	138	2,4,8
	20	207	2,4,8
	20	276	4,8
1.25	20	103	2,8
	20	138	2,8
	20	207	2,8
	150	103	2,8
	150	138	2,8
		207	2,8

TABLE III. FIRING CONDITIONS FOR NO. 2 FUEL OIL

Nozzle (GPH)	Fuel Temp °C	Fuel Pressure kPa gage	Excess O_2 %
0.85	20	207	2,4,6,8
	20	276	<1,2,4,8
	20	345	<1,2,4,8
	90	207	2,4,8
	90	276	2,4,8
	90	345	<1,2,4,8
	150	207	2,4,6,8
	150	276	2,4,8
	150	345	<1,2,8
1.00	20	138	2,4,8
	20	207	2,4,8
	20	276	<1,2,4,8
1.25	20	103	2,4,8
	20	138	8
	150	103	2,4,8
	150	138	2,4,8
	150	207	<1,2,4,8

TABLE IV. CONTRIBUTION OF FUEL NITROGEN TO NO_x

Fuel No.	Fuel Nitrogen %	NO_x Normalized to 3% Flue O_2 PPM
1	.0064	8.1
2	.0120	15.5

TABLE V. EFFECT OF FUEL TEMPERATURE ON TRANSIENT PERFORMANCE 0.85 GPH NOZZLE, 345 kPa, No. 2 OIL

Time After Ignition Min.	Nozzle Temp. °C	Flue O_2 %	Smoke No.	NO_x PPM
0	35			
1.5	60		5	
5	88		0	
10	100	3.1	0	40
15	100		6	
20	100	3.0	5	43
0	71			
1.5	121		0	
5	150	5.0	1	26
10		4.7	0	28
15		4.5	0	
20	150		3	29
23		4.5	1	29

TABLE VI. EFFECT OF FUEL TEMPERATURE AND FLUE OXYGEN ON SMOKE - No. 1 OIL, 1 GPH NOZZLE

Fuel Temp. °C	Fuel Press. kPa	Flue Oxygen %	Smoke No.	CO PPM	CH_4 PPM	THC PPM	NO_x
Without Swirl:							
114	138	4.9	9	118	5	31	11
179	138	4.8	3	45	0	5	23
199	138	4.1	4	10	0	3	19
With Swirl:							
121	138	8.1	0	0	0	0	18
163	138	5.1	1	0	0	0	25
169	138	5.4	0	0	0	0	29
178	138	2.1	3	0	0	0	63

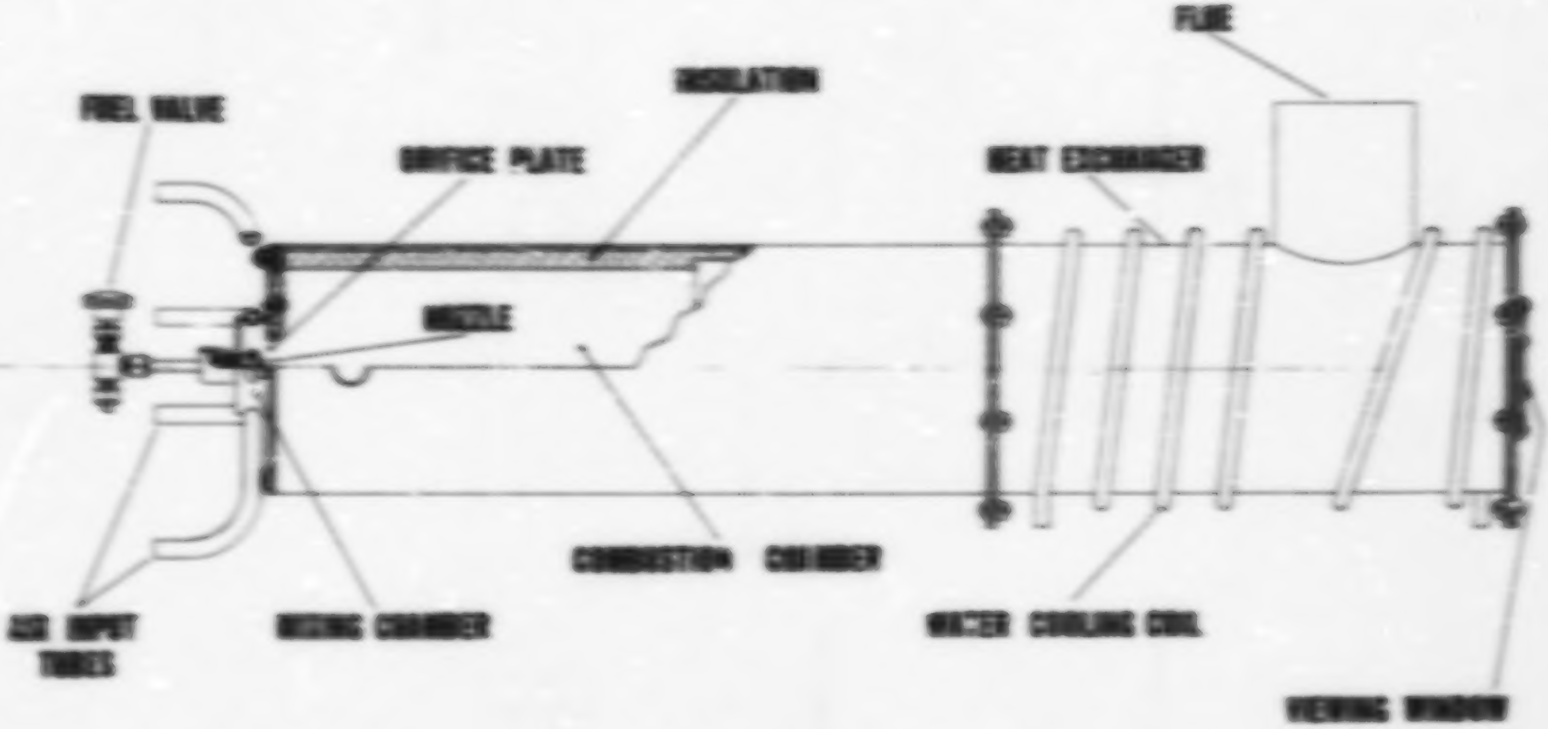
FUEL VALVE
ORIFICE PLATE
INSULATION
NOZZLE
HEAT EXCHANGER
FLUE
AIR INPUT TUBES
MIXING CHAMBER
COMBUSTION CHAMBER
WATER COOLING COIL
VIEWING WINDOW

Figure 1. Experimental burner.

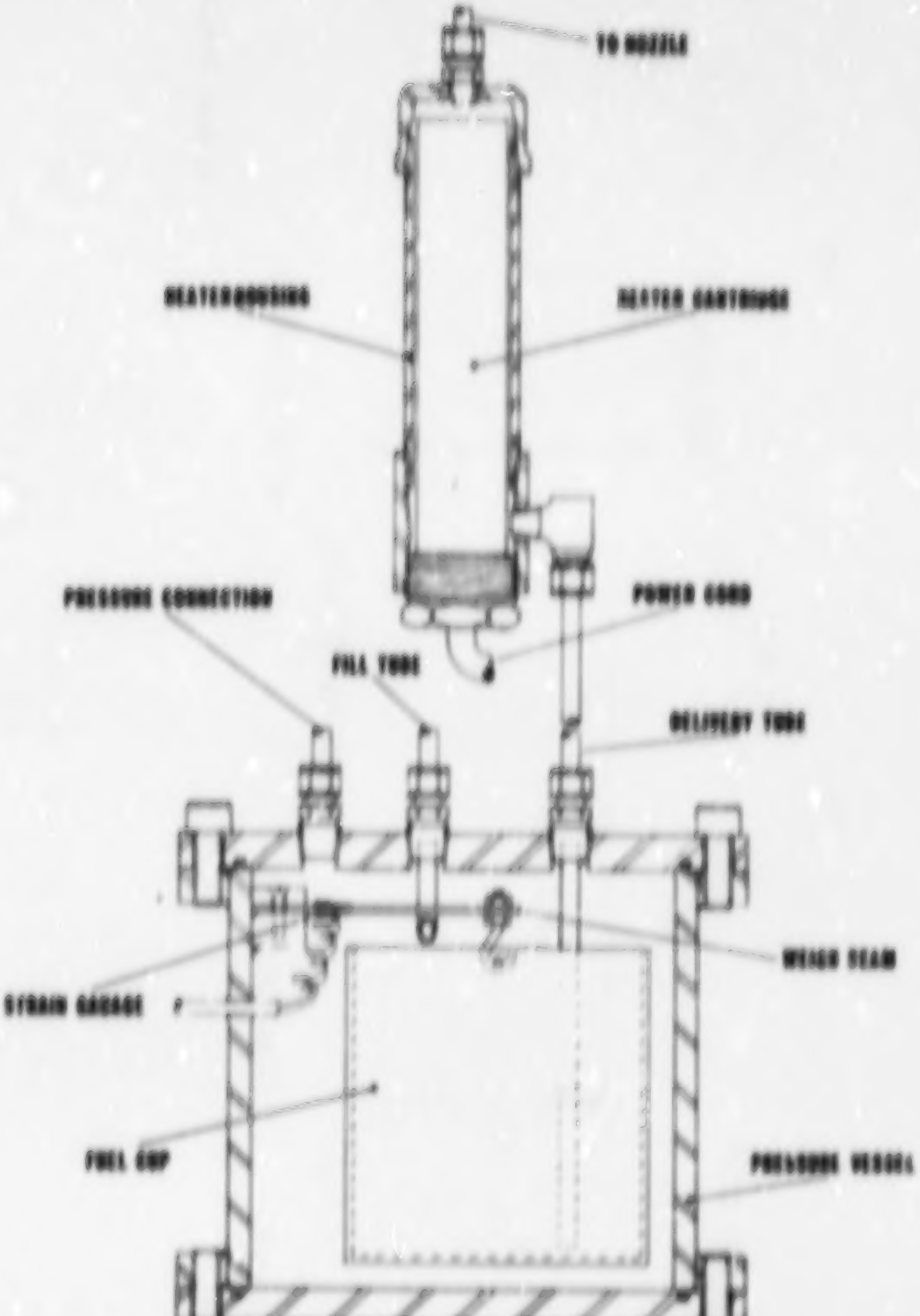
TO NOZZLE
HEATER HOUSING
HEATER CARTRIDGE
PRESSURE CONNECTION
POWER CORD
FILL TUBE
DELIVERY TUBE
WEIGH BEAM
STRAIN GAGES
P
FUEL CUP
PRESSURE VESSEL

Figure 2. Fuel handling system.

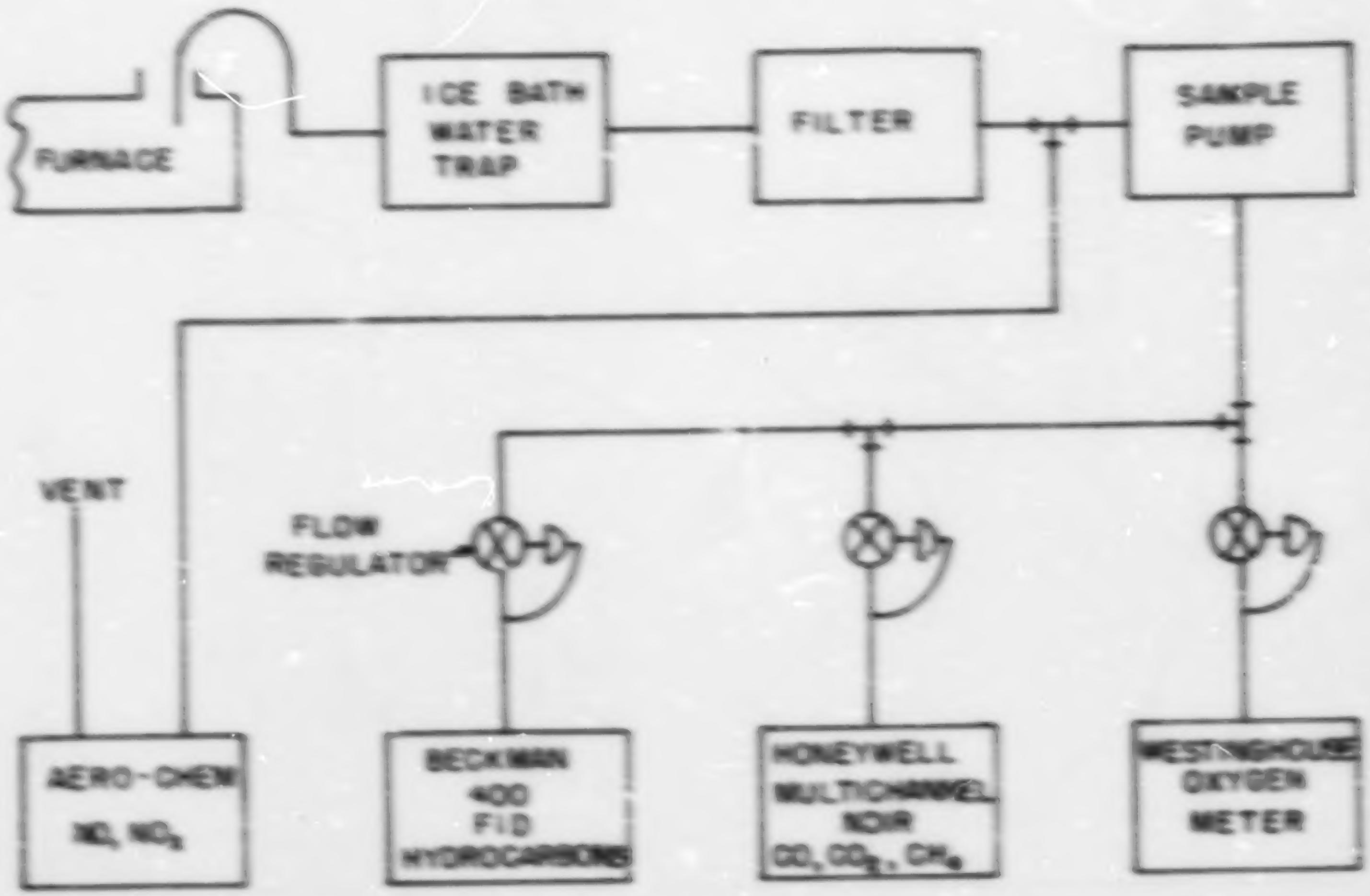
FURNACE
ICE BATH WATER TRAP
FILTER
SAMPLE PUMP
VENT
FLOW REGULATOR
AERO-CHEM NO, NO$_x$
BECKMAN 400 FID HYDROCARBONS
HONEYWELL MULTICHANNEL NDIR CO, CO$_2$, CH$_4$
WESTINGHOUSE OXYGEN METER

Figure 3. Instrumentation.

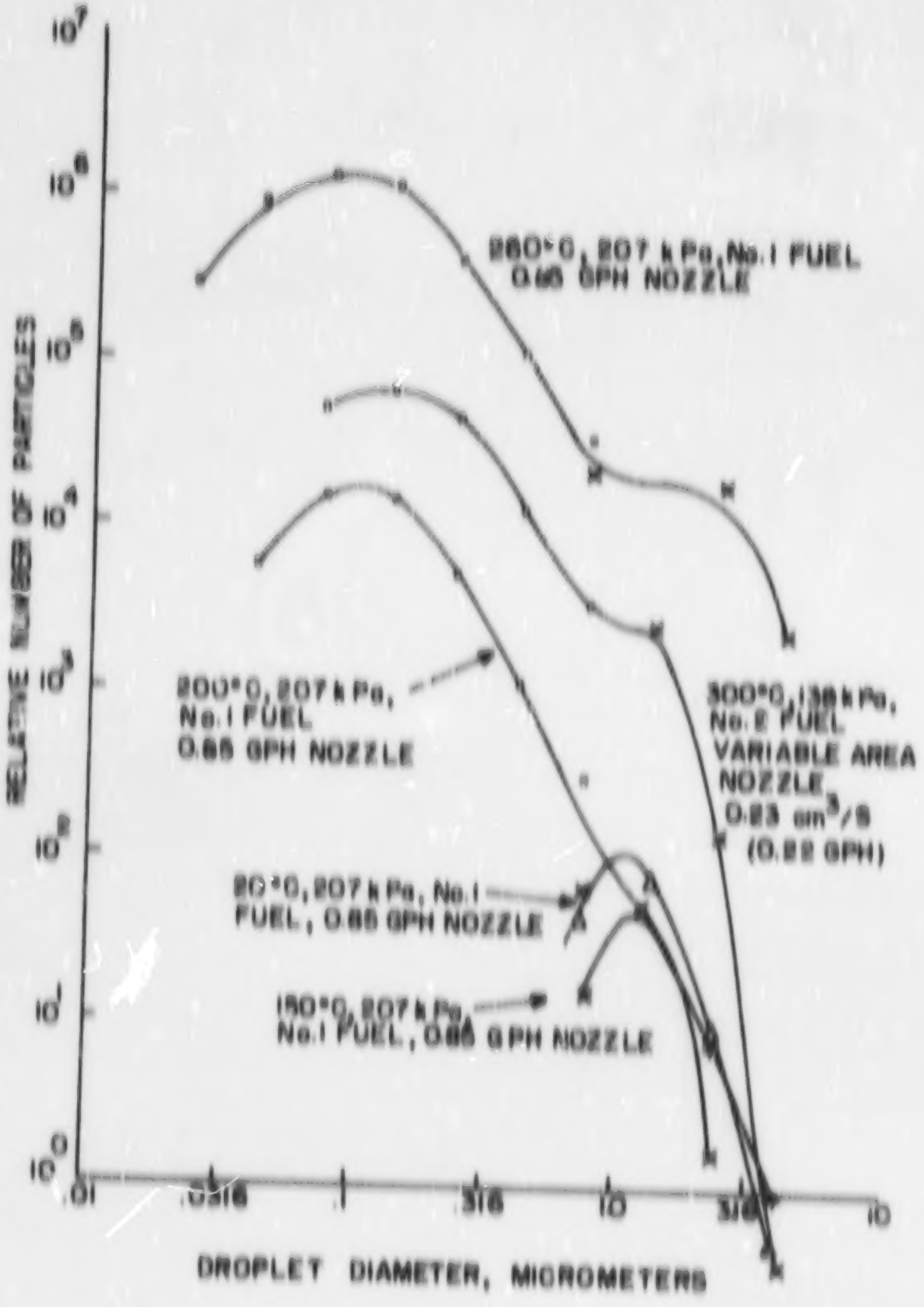

Figure 4. Spray size distribution.

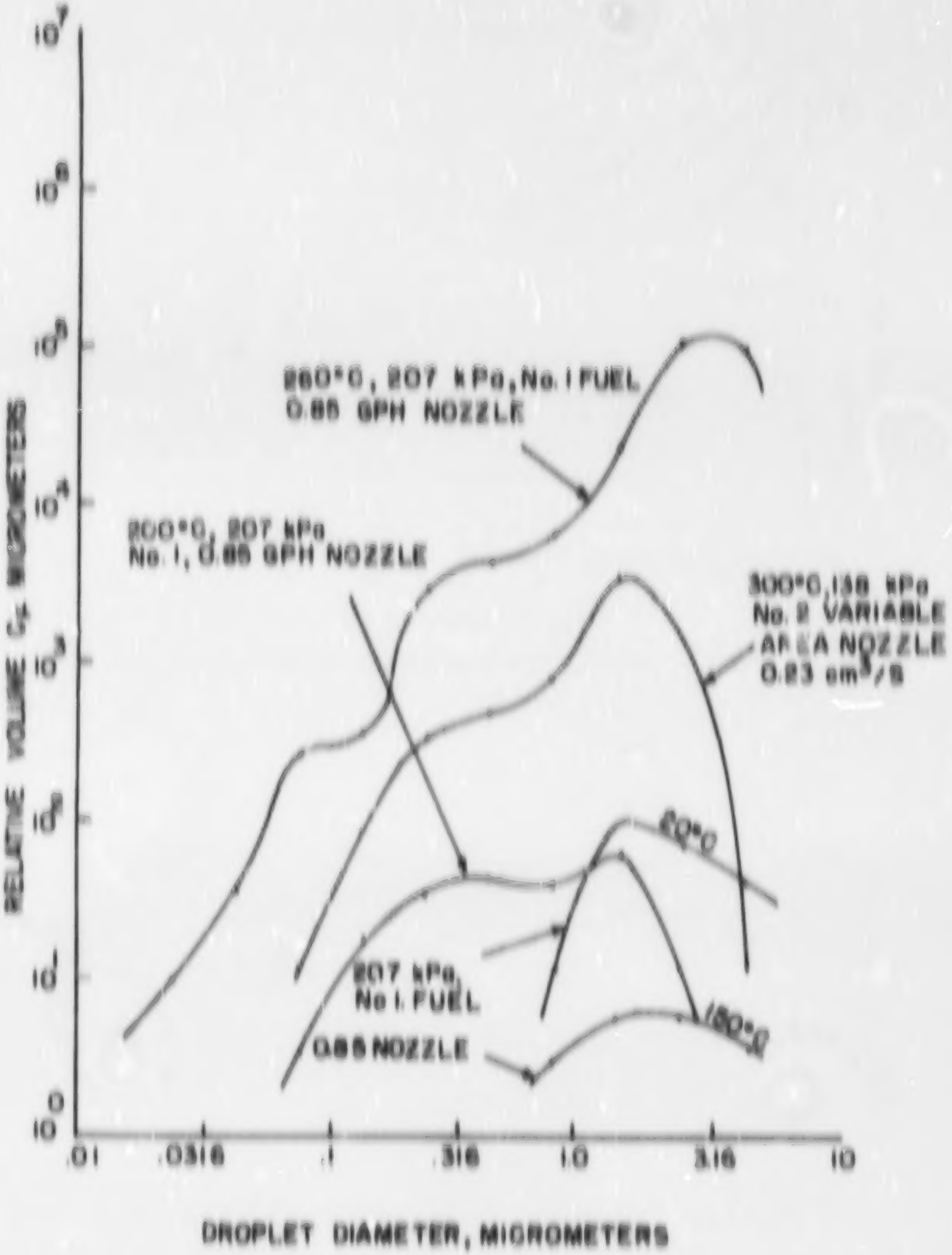

Figure 5. Spray mass size distribution.

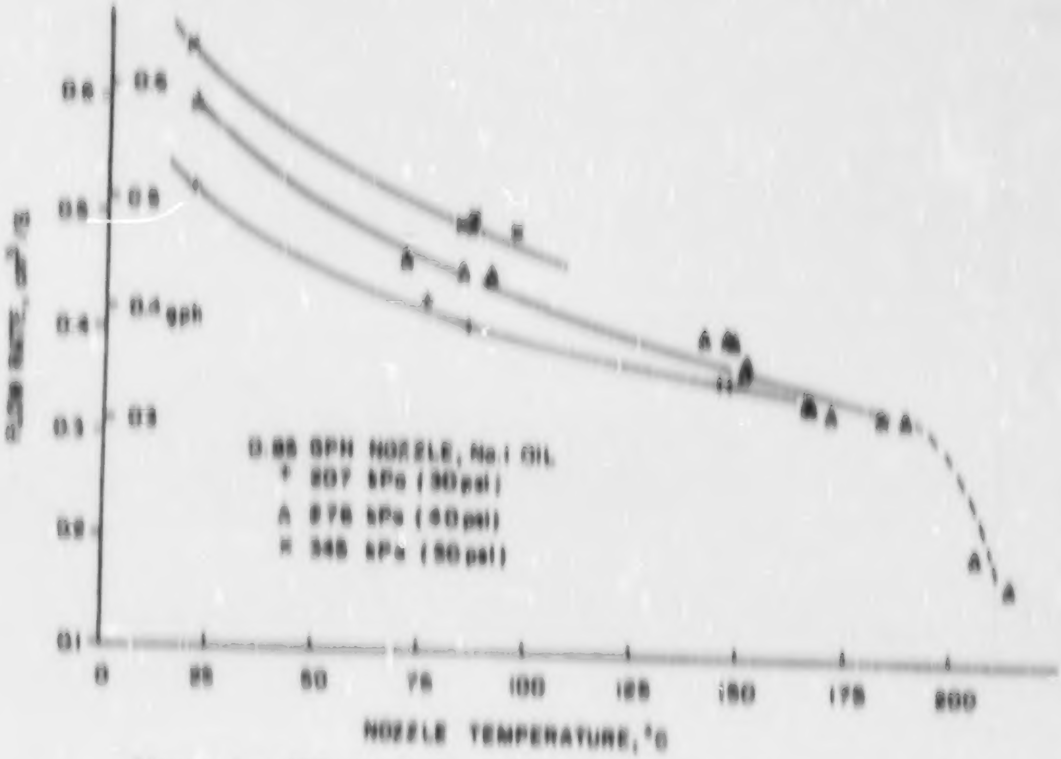

Figure 6. Effect of fuel temperature and pressure on flow.

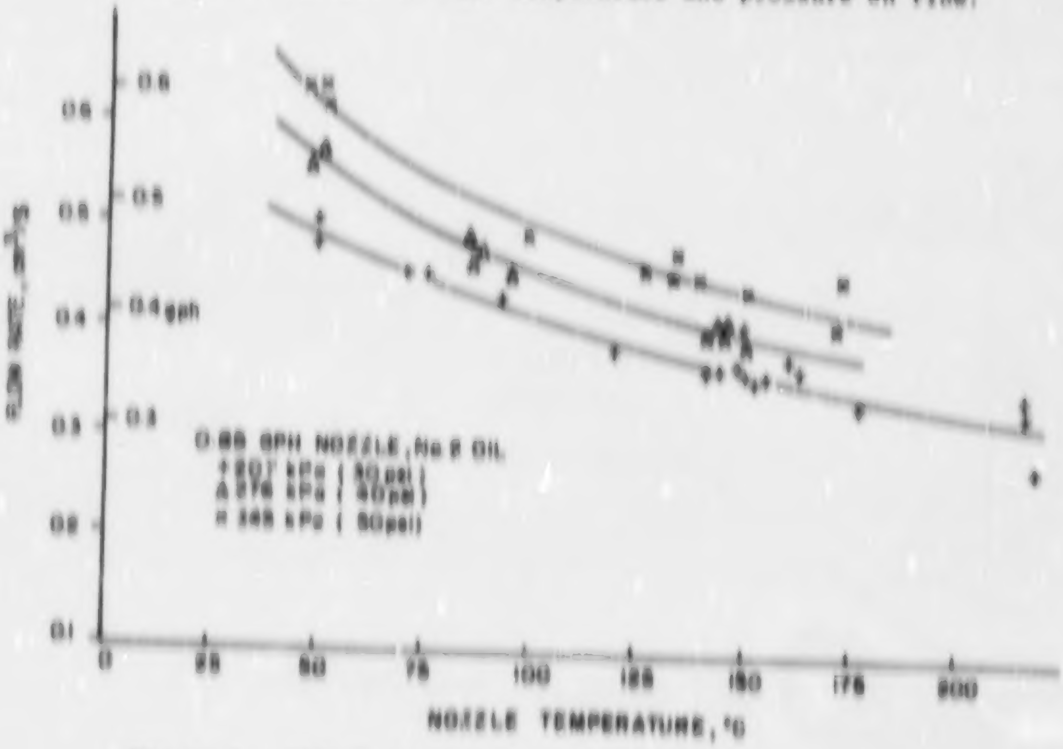

Figure 7. Effect of fuel temperature and pressure on flow.

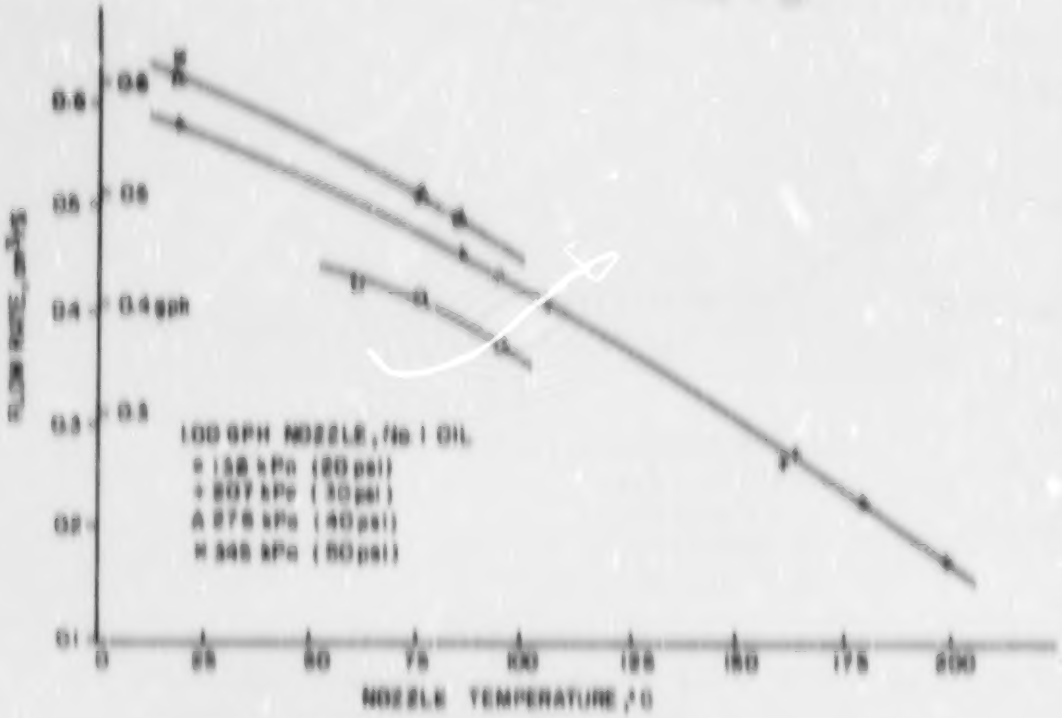

Figure 8. Effect of fuel temperature and pressure on flow

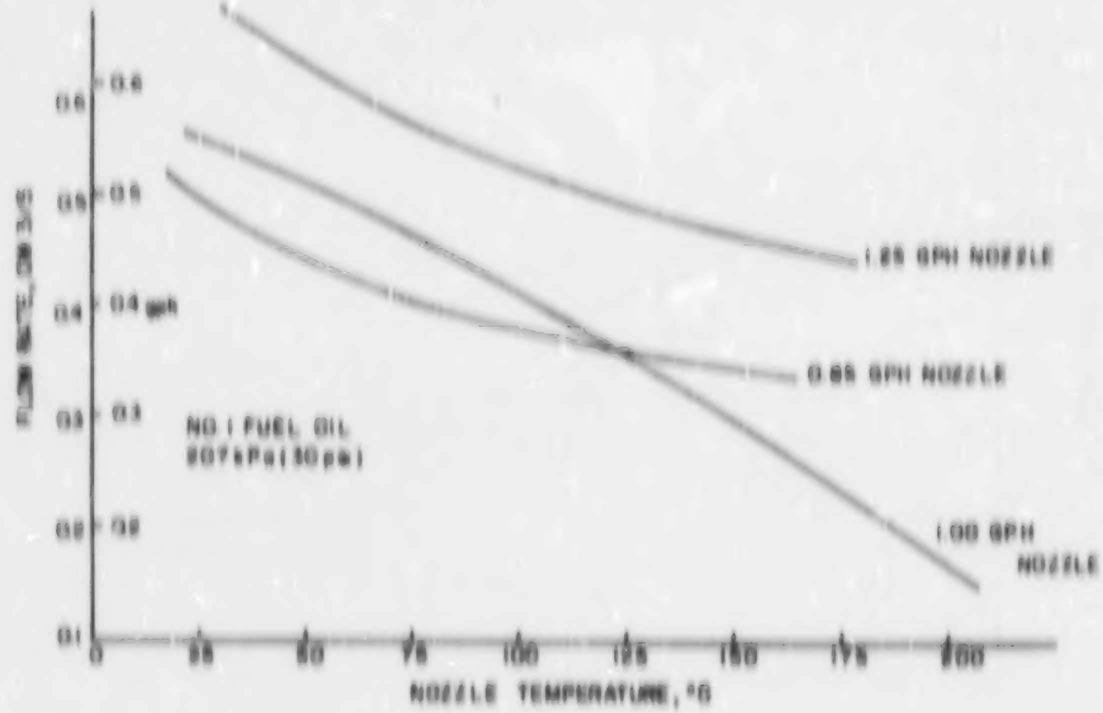

Figure 9. Effect of nozzle size and temperature on flow.

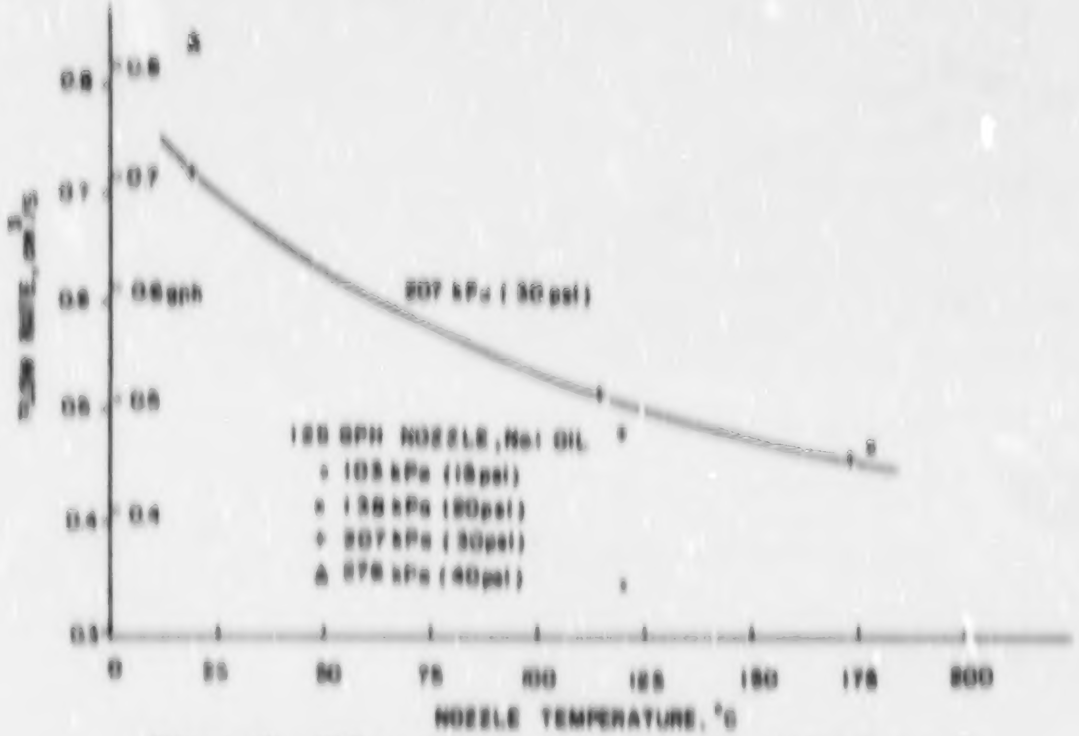

Figure 10. Effect of fuel temperature and pressure on flow.

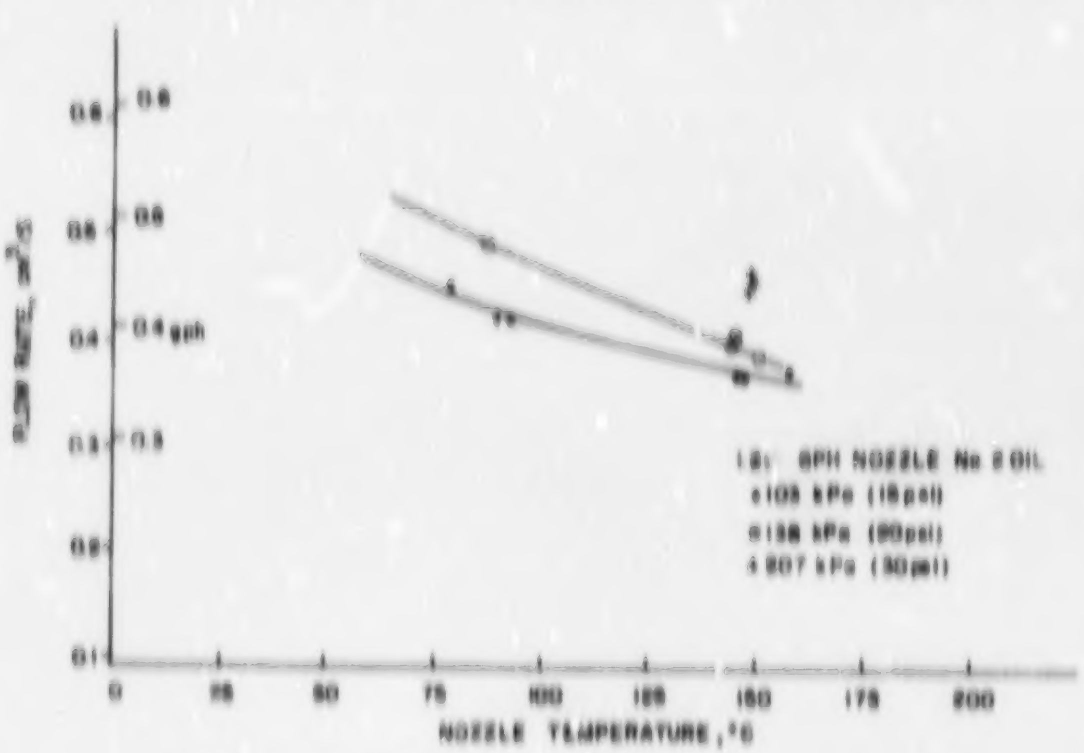

Figure 11. Effect of fuel temperature and pressure on flow.

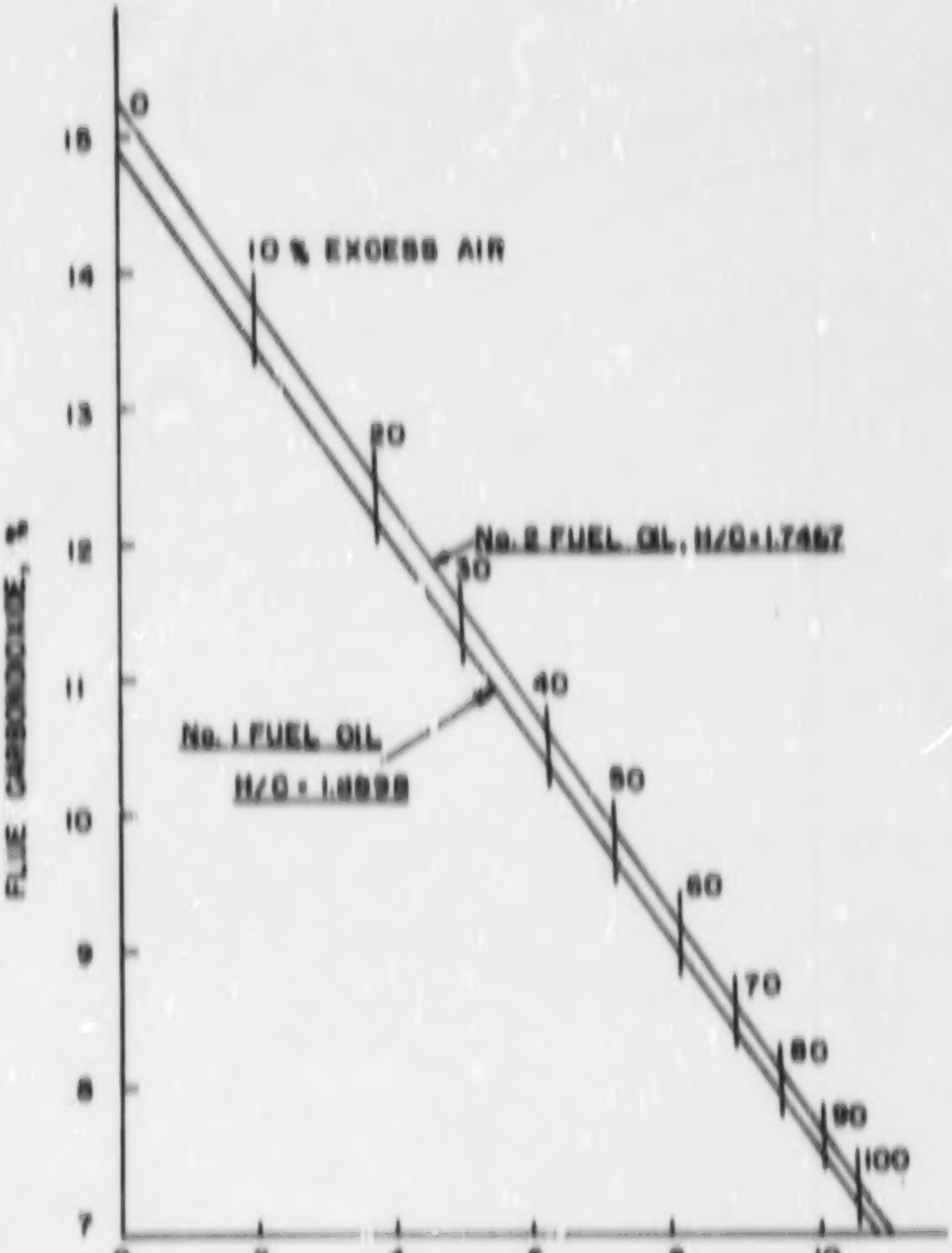

Figure 12. Correlation of flue parameters.

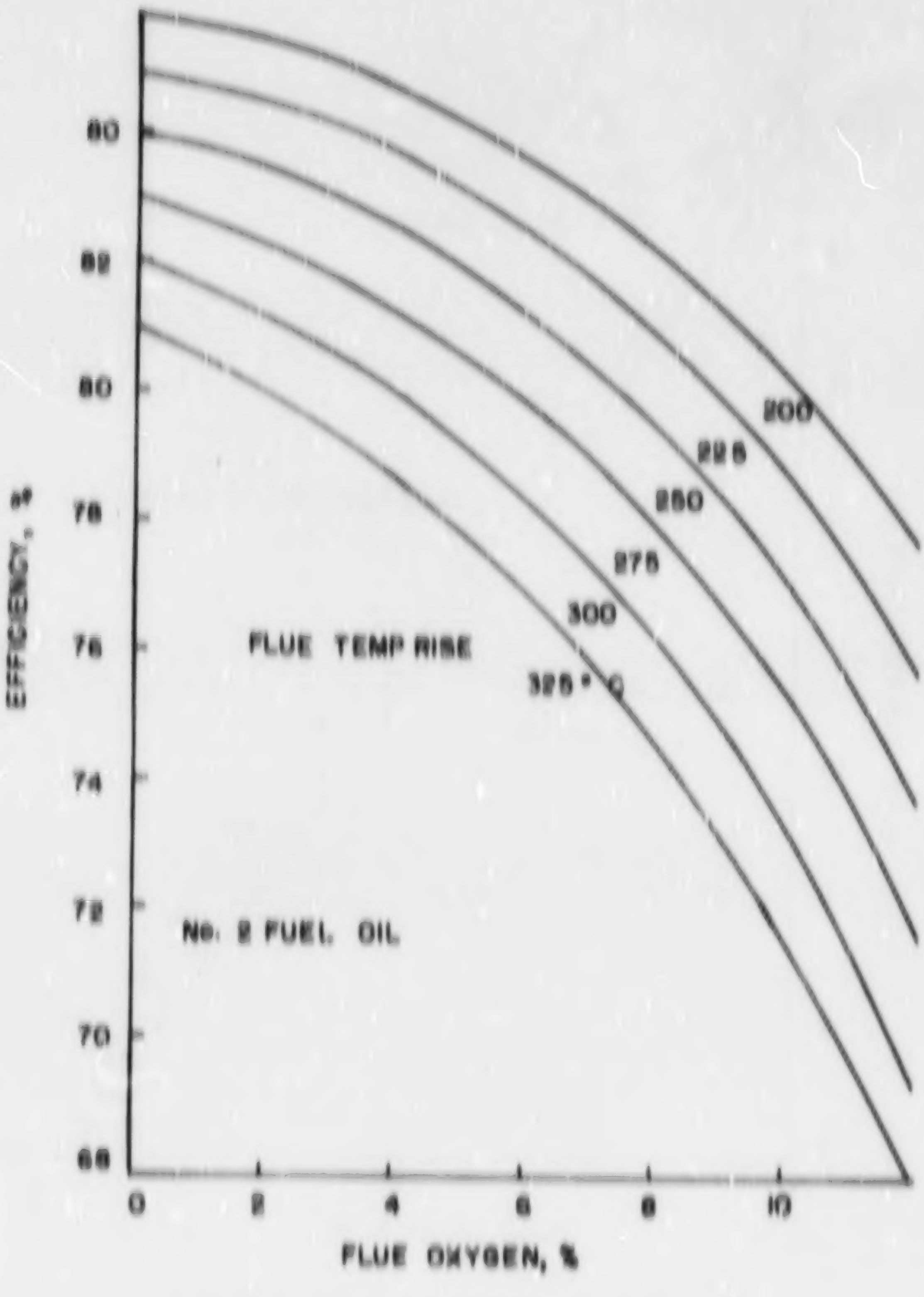

Figure 11. Gross steady state efficiency.

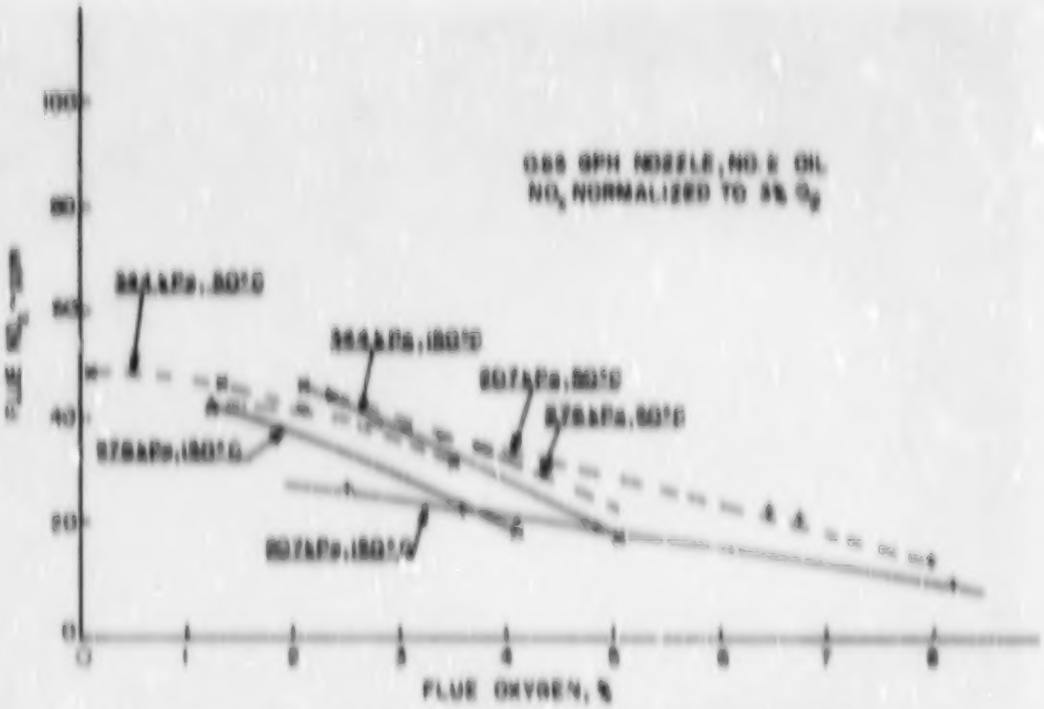

Figure 14. Effect of operating parameters on NO$_x$.

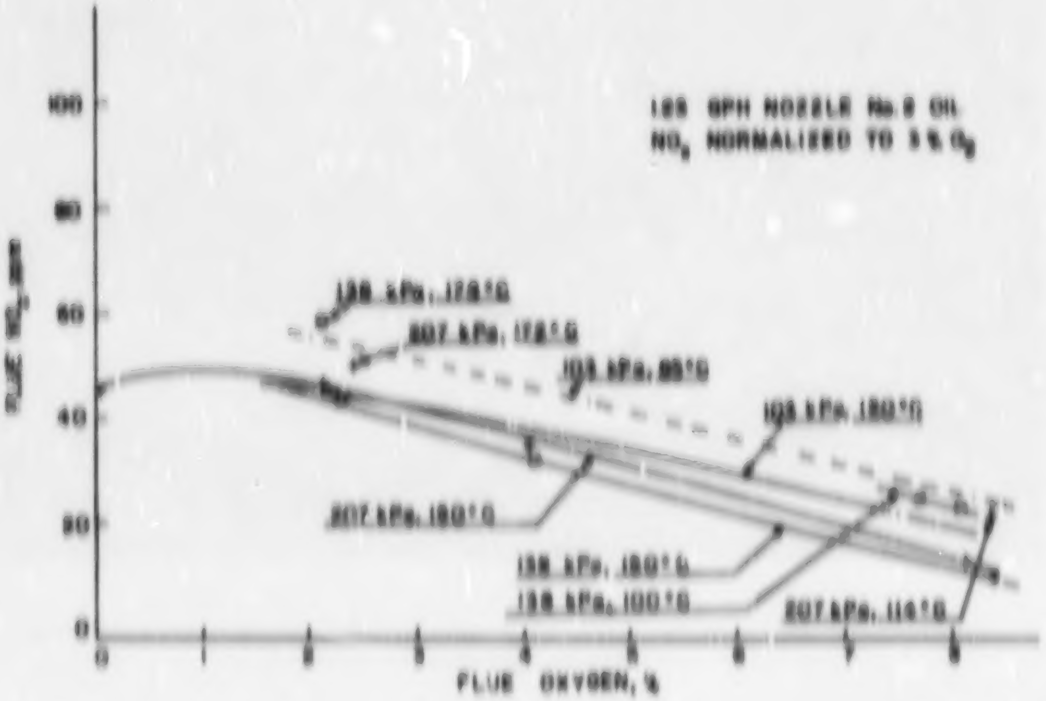

Figure 15. Effect of operating parameters on NO$_x$.

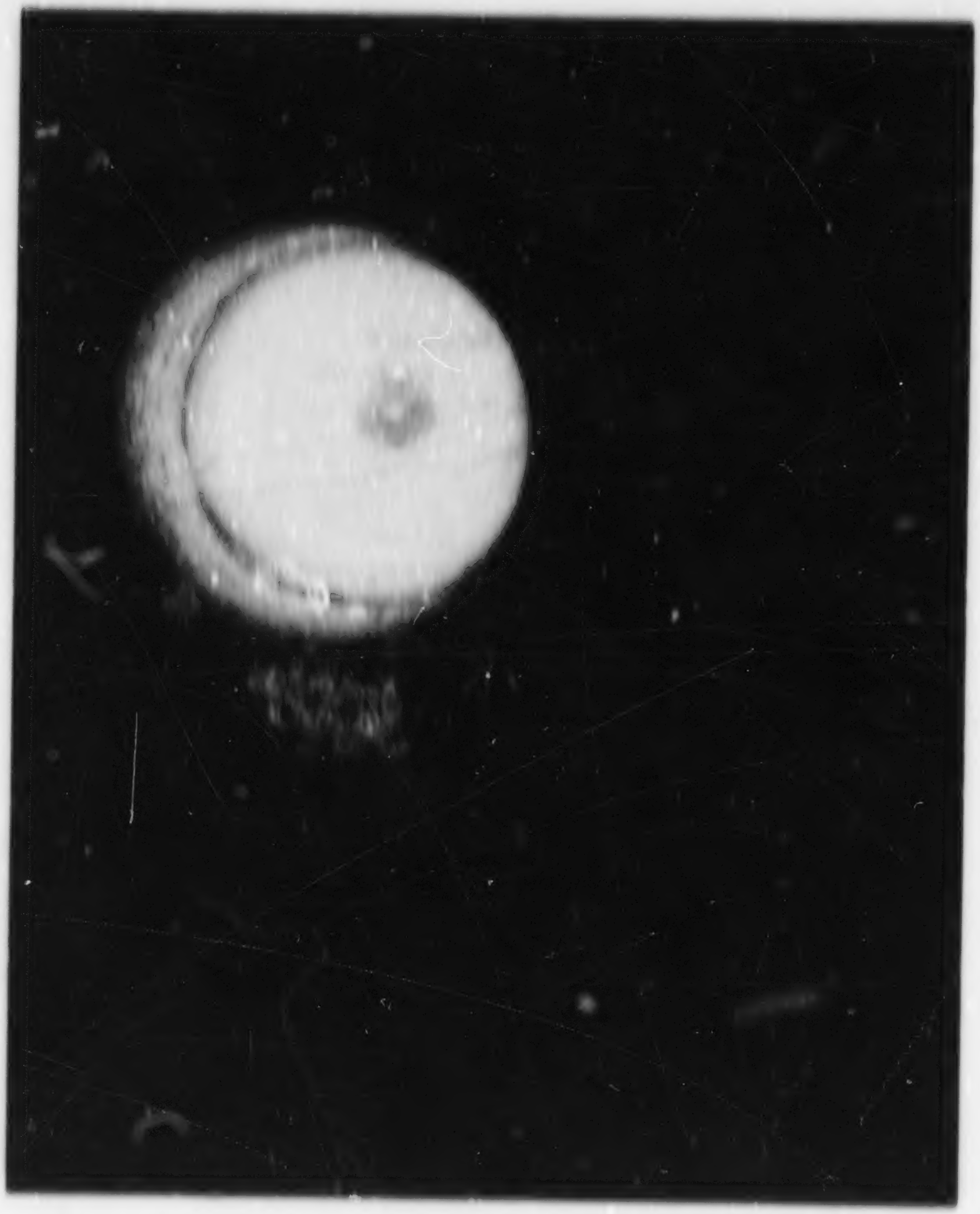

Figure 16. Nonluminous flame with swirl. Dark center spot is inlet orifice with mixing chamber in background.

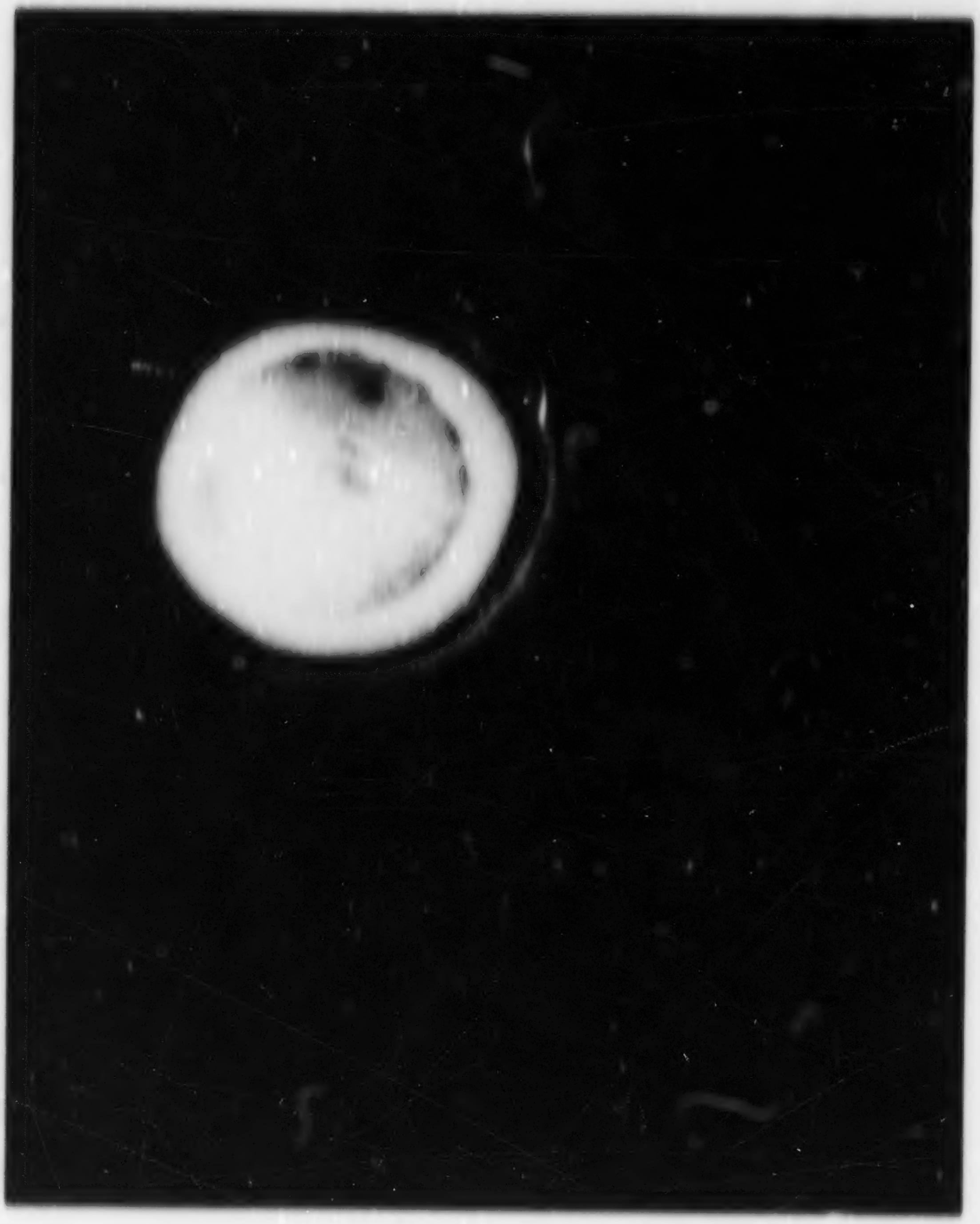

Figure 17. Luminous flame without swirl.

EFFECTS OF FUEL AND ATOMIZATION ON NO_x CONTROL FOR HEAVY LIQUID FUEL-FIRED PACKAGE BOILERS

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This paper was not received in time for publication, and therefore will be included in Volume V.

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NO_x CONTROL TECHNIQUES FOR PACKAGE BOILERS: COMPARISON OF BURNER DESIGN, FUEL MODIFICATION AND COMBUSTION MODIFICATION

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This paper was not received in time for publication, and therefore will be included in Volume V.

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EVALUATION OF EMISSIONS AND CONTROL TECHNOLOGY FOR INDUSTRIAL STOKER BOILERS

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ABSTRACT

Battelle-Columbus is conducting a program to (1) characterize the spectrum of emissions from industrial coal-fired stoker boilers firing several types of coal under various stoker firing conditions, (2) investigate control methods to reduce these emissions, (3) determine the effect of these control methods and variations in stoker-boiler operation on the overall performance of the stoker boiler, and (4) assess the environmental impact of new technology on the future acceptability of stoker boilers.

The program is divided into two phases. In Phase I, the comprehensive emissions characteristics will be determined from the combustion of untreated, reconstituted, and processed coals in Battelle's 20-hp stoker-boiler small-scale stoker. Appropriate data will be collected to determine if criteria pollutants are responsive to changes in fuel, stoker operation, or combustion parameters. From the results of the Phase I research, an assessment will be developed that will include defining the complete pollution potential for untreated, reconstituted, and processed coals for improving the environmental acceptability of stoker-boiler technology. This assessment will also relate the results of the small-scale stoker-boiler investigation to larger scale stoker boilers.

Phase II will be conducted to identify and evaluate potential control concepts for control of emissions from full-scale industrial stoker boilers. The Battelle steam plant 600-hp spreader-stoker boiler will be utilized and modified to evaluate potential control concepts. This phase will provide a systematic evaluation of control concepts while firing several representative stoker fuels. Also, the most promising treated coal identified in Phase I will be evaluated and compared with alternative control techniques. Based on the results of the research program, an assessment will be developed to define the potential of emissions control on the overall acceptability of industrial stoker coal-fired boilers to meet our nation's energy needs. In addition, recommendations for future applications of stoker modification control will be made.

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EVALUATION OF EMISSIONS AND CONTROL TECHNOLOGY FOR INDUSTRIAL STOKER BOILERS

by

Robert D. Giammar

INTRODUCTION

The firing of boilers for process steam, space heating, and on-site power generation accounts for about half of all the fuel used by American industry--nearly as much as that consumed in the generation of electricity by utilities. Coal was once the dominant fuel for such industrial boilers; it now provides only about one-quarter of their fuel.

Economic and environmental factors over the past 30 years made coal relatively unattractive for industrial boilers. Both the capital and operating costs of coal-fired boiler installations have been inherently higher than those of equivalent facilities designed for gas and/or oil firing. Thus, with the widespread availability of oil and gas in the late 1940's and early 1950's, there was a drastic decline in the demand for the industrial stoker. Only in some of the largest boiler installations could the savings resulting from the somewhat lower fuel cost of coal offset the greater capital and operating costs. As a consequence, there has been little incentive for manufacturers to improve stoker technology through research and development.

Stoker-fired boilers are now at a further disadvantage with respect to environmental considerations, as their emissions of the criteria pollutants (specifically particulate and SO_2) are high in comparison to gas- and oil-fired boilers. In addition, because of the chemical composition of coal, other potentially harmful species such as

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POM and trace elements are emitted during stoker firing. The establishment of stringent air-pollution regulations in recent years (with national standards for large new installations and local standards for many other installations) has accentuated the economic disadvantages of stoker boilers. Costs of installing and operating the downstream control equipment that is needed to control emissions of fly ash and SO_2 for industrial boilers are often a significant portion of the boiler facility and its operation.

However, with the impending national shortage of natural gas and fuel oil, industry must again consider the relatively abundant source of coal to meet its energy needs. For the commercial and small- and intermediate-size boilers, the stoker has been demonstrated to be the most effective method of direct firing of coal. Although the economic aspects involved with coal firing are becoming less dominant, some environmental problems need to be resolved before stoker utilization can gain wide acceptance.

Accordingly, EPA has funded a research and development program that will identify and demonstrate improvements in stoker coal firing that can provide an incentive for greater industrial use of coal--a step that enables the greatest flexibility in the nation's fuel resources. The subsequent sections of this paper discuss this as well as pertinent background information. Because this program was only recently activated, there are no data to report at this time.

OBJECTIVES AND SCOPE OF PROGRAM

OBJECTIVES

The overall objectives of this program are:

(1) To characterize the spectrum of emissions from industrial coal-fired stoker boilers firing several types of natural and processed coals

(2) To investigate control methods to reduce these emissions

(3) To determine the effect of these control methods on the overall performance of the stoker boiler

(4) To assess the environmental impact of new technology on the future acceptability of stoker boilers.

SCOPE

The scope of this program can be summarized as follows:

Coal Types

- Untreated or raw
- Reconstituted
- Processed

Pollutants of Interest

- Criteria pollutants (SO_2, NO_x, CO, HC, and particulate)
- Level 1 pollutants
- Selected Level 2 pollutants

Experimental Units

- Existing 50-hp stoker-boiler with stack sampling facilities (EPA owned; located at Battelle-Columbus)
- Battelle's existing 600-hp spreader stoker boiler with provisions for stack sampling

Systems Operating Parameters

- Excess air levels
- Boiler loads
- Overfire air rates
- Fly-ash reinjection (600-hp boiler only)

Modification of Stoker Operation

- Overfire air modifications
- Steam injection above bed
- Optimization of fly ash reinjection rates
- Optimization of primary/secondary air flow rates
- Other modifications evolved during performance of program

Modification of Stoker System

Candidate modifications include:

- Zoned air admissions (to control primary air to different parts of bed)
- Modified coal feeding at low-load (as by hybrid spreader-over-feed approach)
- Small oil burners fired above bed as afterburners

- Flue-gas recirculation
- Staged-combustion
- In-furnace control of SO_2 by limestone addition to fuel bed
- Other modifications as deemed appropriate.

TECHNICAL BACKGROUND

A slow trend back to coal as a fuel for industrial boilers is now evident. Potential future disruptions in foreign oil supply, rapidly rising oil and gas costs, political and economic decisions arising out of balance of payment problems, and dislocations in domestic gas and fuel oil supply appear certain to force this continuing trend back to coal.

The concept of stoker firing has important attributes for commercial and industrial boilers that have not yet been fulfilled by alternative methods of coal firing or by coal-derived fuels. However, because of the relatively small market for stokers in recent years, there has been no incentives for manufacturers to improve stokers designs that have remained unchanged in the past 20 years. Therefore, to meet current emission standards with stoker firing, expensive (or not fully proven in the case of SO_2 control) flue-gas control equipment or premium coals (low sulfur, low ash and in limited supply) will have to be utilized. Modifications in stoker design and operation offer possible approaches for improvement in the overall acceptability of stoker firing. Alternatively, consideration should be given to the use of coals that have been treated or have undergone a change in their chemical properties to make them more environmentally acceptable.

TRENDS IN COAL FIRING

Recent Battelle studies directed to the characterization of the industrial boiler population provide some insight as to trends in coal-firing methods by boiler size range. Information on the industrial boiler population and design trends was developed in a special survey of boiler manufacturers conducted jointly by Battelle and the American Boiler Manufacturers Association (ABMA) and reported in Reference 1. These results were later refined based on the basis of an analysis of recent sales data for industrial-size water-tube boilers, plus overall judgement of Battelle and ABMA staff(2).

Firing methods are boiler-size dependent. Thus, different size categories are defined as follows for the presentation of trend information:

Size Category	Size Range, pph*
A	10 - 16
B	17 - 100
C	101 - 250
D	251 - 500

Smaller boilers are placed in the "commercial" class and larger boilers are considered to be "utility boilers".

Figure 1 shows trends in coal-firing capability estimated for boilers in these four size categories installed in 1930, 1950, and 1970 and forecasted for 1990(2). The data apply to boilers designed to fire coal or having a capability to fire coal as a secondary fuel. This distribution is shown as a percentage of all industrial boilers. The projection for 1990 was revised by Battelle from the earlier survey on the basis of the following broad assumptions:

- Oil and gas supplies will be limited
- Oil and gas will be utilized in smaller equipment and for high-priority uses (but not fully by mandatory allocation)
- Coal will dominate new installations in the larger sizes
- Clean liquid and gaseous fuels from coal conversion processes will not be available in large quantities by 1990
- Firing refuse as a supplementary fuel will increase, but will not become significant in terms of percentages.

The coal projection includes the firing of chemically refined solid fuels, but does not include future synthetic liquid or gaseous fuels derived from coal.

---

* pph = pounds (of steam) per hour.

The trends in Figure 1 indicate that coal was the dominant fuel for industrial boilers in the pre-World War II era and that most boilers had a coal-firing capability. By 1950, percentage of units with a coal-firing capability dropped dramatically for boilers being installed in the smaller size categories; in the largest size categories, 65 percent of the new boilers had coal firing capability. By 1970, coal firing nearly disappeared from the smaller boiler size categories, but 40 percent of the largest boilers were being installed with a capability to fire coal.

For the future, a return to the capability for direct firing of coal is forecasted for new installations in the next 15 years, especially in larger sizes, where about 70 percent of the new boilers are expected to have coal firing capability. In the event of new legislation and/or fuel priority allocations that prohibit firing gas and oil in large boilers, all new industrial boilers may be required to have a coal firing capability. Some large industrial companies have already made the decision to provide for a coal capability in new installations as a measure of insurance to keep manufacturing plants operating in the face of an uncertain fuels situation.

TRENDS IN STOKER FIRING

Industrial Coal Firing Methods

Figure 2 shows trends in coal firing methods for industrial boilers in each of the four size categories as developed in the studies cited earlier.[1] Firing methods included in these data are

- Stoker Types
  - spreader
  - underfeed
  - overfeed (chain grate, traveling grate, or vibrating grate)
- Other
  - pulverized coal
  - miscellaneous (cyclone, refuse, sawdust, wood, etc.)

The following overall observations can be made from Figure 2:

- Before the introduction and commercialization of the spreader stoker in the 1930's, underfeed stokers dominated the smaller size categories and had an appreciable share of the market in the larger sizes. The overfeed types were significant in all sizes, especially larger sizes. Firing of pulverized coal was significant only in the largest sizes.
- By 1950, the spreader stoker had gained a significant share of the market below 250,000 pph, mainly displacing overfeed stokers below 17,000 pph and underfeed stokers from 17,000 to 100,000 pph. Pulverized coal made some inroads in the size category from 101,000 to 250,000 pph during this period.
- In the 1950's and 1960's, the penetration of spreader stokers into the share of the underfeed stokers market continued to the point that it was the dominant type for the range of sizes encompassing 17,000 to 250,000 pph. Pulverized-coal firing gained further, nearly dominating the market above 250,000 pph by 1970.
- For the near future, spreader stokers can be expected to continue to gain popularity in the smaller sizes with underfeed stokers holding the major share below 17,000 pph. Spreader stokers can be expected to decline slightly in the market share above 100,000 pph as smaller coal-fired units make gains.

It should be noted that introduction and successful commercialization of the fluidized-bed combustion concept to industrial boilers could begin to displace the more conventional firing methods during the late 1980's and, thus, significantly alter the boiler population beyond 1990, especially for units above 100,000 pph.

The spreader stoker has gained a significant share of the stoker market for several reasons. This type of stoker is a highly versatile device that has greatly simplified the industrial utilization of coal by being relatively insensitive to coal properties. Thus, the spreader stoker can fire both caking and non-caking coals and coals with a broad range of ash and moisture contents. It is also the most flexible and responsive stoker firing method for fluctuating steam loads. However, the spreader stoker also has some limitations that include inherently high fly ash carryover due to suspension burning and a tendency to produce smoke at low boiler loads.

Although the underfeed and overfeed stokers are have been declining in popularity, there still will be a market for these types of stoker, particularly in the smaller size categories. In addition, many boilers originally built with these type stokers but later converted to gas or oil firing, can be converted back to stoker firing. Accordingly, any assessment of the economic and environment feasibility of stokers should include the overfeed and underfeed types.

The design and operation of each of the three basic types of stokers (overfeed, underfeed, and spreader) are significantly different with the result that each has its specific operational characteristics.

Status of Stoker Technology

Stoker development continued until the 1950's when the market decreased drastically with the widespread availability of oil and gas. Present stoker-boiler designs are essentially based on those of the 1950's. Incentives for further technical development of stokers has been nonexistent. Until recently, the economic factors have clearly favored oil and gas firing over stoker firing.

Manufacturers of both stokers and boilers believe that stoker boilers have been developed to a level that is technically competitive with oil- and gas-fired boilers. Criteria have been established to provide practical guidelines on combustion parameters that include furnace volume, gas passages, baffle arrangements, and heat-transfer surface area. In addition, the utilization of soot blowers, fly-ash collectors, refractory arches, fly-carbon reinjection systems, overfire air jets, and combustion controls to coordinate air and fuel supply with changing loads has improved the overall efficiency and cleanliness of the stoker boiler. Selection of low volatile, low-ash, and low-sulfur coals will also minimize the low-load smoke (from spreader stokers), fly-ash control, and SO_2 control problems associated with burning coal.

Economic Status--

Coal has in recent years failed to compete with oil and gas for industrial steam raising because of the higher first costs, higher operating costs, and higher maintenance costs of the coal-fired boiler units. Thus, even when coal was the lowest cost fuel (in terms of cost per Btu), many users chose the cleaner fluid fuels. Many plants no longer have that choice. Gas is unavailable to many, and oil is very costly with uncertain supply. Coal can replace oil or gas for some larger industrial users, if some measure of control can be attained over SO_2 emissions.

Figure 3 provides a comparison of steam-generation costs for various fuels on the basis of a load factor of 0.30, a boiler efficiency of 0.80, and an annualization rate of 16.7 percent. These estimated costs include both capital and operating expenses. It is apparent from the example shown that the stoker boiler is economically attractive when the cost differential between stoker coal and other fuels is greater than $\$1/10^6$ Btu (approximately $26/ton), steam-generation costs would be approximately $\$3/10^3$ lb of steam. In an oil or gas boiler, the fuel costs would have to be no higher than $\$2/10^6$ Btu to generate steam at $\$3/10^3$ lb. In the past, the cost of all industrial fuels was much less than $\$1/10^6$ Btu and cost differentials were about $\$0.50/10^6$ Btu between fuels.

Figure . also indicates the steam costs from a stoker boiler equipped with SO_2 scrubbing equipment. Because of these relatively high estimated costs, it is unlikely that SO_2 scrubbing will be utilized with medium-size industrial boilers (unless dictated by government regulation).

EMISSIONS AS RELATED TO COAL COMPOSITION AND STOKER OPERATION

Table 1 summarizes the emission factors[a] for criteria pollutants established by EPA as averages for fossil-fuel combustion(1). The higher emission factors from coal combustion as compared to those from oil or gas combustion can be attributed to the composition of the coal itself and/or to the design and operation of the stoker.

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[a] The emission factor as used here is a statistical average of the rate at which a pollutant is released to the atmosphere per unit of fuel consumed(1).

Coal Composition

As noted in Table 1, particulate and sulfur dioxide emissions are significantly higher for coal combustion especially considering that coal can have an ash content as high as 25 percent and a sulfur content as high as 4 percent. Sulfur retention in coal ash is relatively low compared to the conversion of sulfur to sulfur dioxide. Likewise, the conversion of fuel nitrogen to NO can be significant as some coals contain as much as 2 percent nitrogen. In addition, the combustion of coal emits trace elements at levels much greater than those from oil or gas because the concentrations of most trace elements are greater in coal.(4)

Trace quantities of POM are generated by nearly all combustion processes. Although combustion of natural gas can lead to the formation of POM, POM formation is favored by the presence of the cyclic structure of high molecular weight radicals and molecules in the fuel, which are considerably more abundant in coal.(5) In addition, it is conjectured that coal has certain other properties that enhance the potential for POM formation upon firing. For example, data from a 20-hp boiler fired by an underfeed stoker (in cyclic operation) suggest a relation between POM emissions and coal rank and volatile matter as evidenced by

	Volatile Matter, percent	POM Emissions, mg/lb coal burned
Anthracite	4	1
High volatile bituminous	40	70
Low volatile bituminous	21	30
Western subbituminous	36	10
Lignite char	16	2

with POM generally increasing with volatile matter in the coal.(6) However, other factors may also be relevant, such as the free swelling index (measure of the caking tendencies of a coal that affects the overall performance of some stokers).

Stoker Operation and Design

As noted in Table I, the products associated with incomplete combustion (CO and HC) are higher for coal than for oil and gas. These are primarily attributed to inhomogeneity of the air/fuel ratio over the entire bed. For some industrial underfeed stokers, fuel beds are extremely nonuniform, ranging in thickness from 6 inches to over 2 feet. Also, for coking coals, the fuel bed often contains large fissures separating masses of coke. As a consequence, there are regions in the bed that have an excess amount of air while others have a deficiency of air.

In addition, because of the coal ash, the stoker has the inherent problem of fly ash carryover that can result from a disturbance of the bed. In the case of the spreader, approximately 50 percent of the coal is burned in suspension with a significant amount of fly ash carried out with the flue gas. In some spreader-stoker systems, to recover the carbon in this fly ash, a portion of the fly ash is reinjected into the furnace for re-burning. This results in a higher fine particulate loading, necessitating the utilization of the highest efficiency particulate collectors.

EMISSIONS CONTROL TECHNIQUES FOR COAL FIRING

Techniques have been developed to control emissions from coal firing. Flue-gas control devices (electrostatic precipitators, scrubbers, baghouses, etc.) have been successfully utilized to control particulate emissions, but control devices aimed at SO_2 control (notably scrubbers) have been substantially less successful. This equipment is expensive and must be maintained. Alternatively, the firing of coals that produce low emissions (low sulfur-low volatile-low ash coals), either naturally or by treatment offers another possible emissions control technique. Likewise, modification in the design and operation of the stoker to provide an improved control of the combustion processes offer another potential emissions control technique.

Fly Ash Collectors

Commercially available particulate control equipment has been utilized for many years and has been demonstrated effective in controlling fly ash emissions from stoker boilers. Nearly all stoker boilers sold today have a particulate removal system of some type. The simplest systems are mechanical dust collectors (dry cyclones) that are effective in removing only the largest fly ash particulates. Depending upon the ash content of the coal and the stoker design, these mechanical collectors are often sufficient to meet local codes. To meet the Federal standards for particulates, the mechanical collector must be followed by either a wet scrubber, electrostatic precipitator, or fabric filter. Generally, the electrostatic precipitator has been found to be the most cost-effective device and is most often used. Designs have been recently improved to produce efficiencies of over 99 percent. The wet scrubber might gain popularity for particulate control -- if it can also reduce SO_2 emissions. In summary, particulate removal equipment is available with collection efficiencies approaching 100 percent. The equipment has been proven reliable and is available from many manufacturers.

Stack Gas Cleanup Systems for SO_2 Control

There are only a few industrial boiler installations utilizing some form of SO_2 cleanup. In general, these systems have been expensive and unreliable. There are numerous processes under development, but only a few are applicable to the industrial-size boiler. Alkali scrubbing systems offer the most promise. The open-loop, once-through NaOH scrubbing system has been demonstrated to be fairly reliable, but the scrubber effluent can present a water pollution problem. To avoid the sodium-salt waste disposal problem, the scrubber effluent can be reacted with limestone and/or lime to regenerate the NaOH, which is then returned to the scrubber. This closed-loop process is referred to as the dual- or double-alkali system. This system has not yet been demonstrated to be fully reliable. The system does show promise as an SO_2-removal process, but further development is needed to make it more reliable and less expensive.(7)

Coal Selection

Of the criteria pollutants, particulate and SO_2 are the two that can best be controlled by proper coal selection.

Particulate--

Although it is not technically feasible to select a coal that would eliminate the need of a control device to meet particulate emission standards,* appropriate selection would minimize those emissions and also the need for the highest efficiency collectors. To meet air pollution standards, a coal with essentially no ash would be required, however, a minimum of about 6 percent ash is needed to protect stoker grates from being overheated. Utilization of low ash coals (6-10 percent) washed, dust-treated, and double screened coal (not more than 20 percent below 1/4 size) would minimize fly ash carryover. Likewise, selection of free burning coals will enhance overall stoker performance and, thus, minimize particulate loading.

SO_2--

The Federal standard for SO_2 emissions is 1.2 lb/10^6 Btu of heat input. To meet this standard without control equipment requires that high-ranking coal with a sulfur content of less than 1 percent be utilized. Several states have even more stringent requirements, regardless of the size of the combustion equipment, and because of this fact, many coal-fired boilers were being converted to gas or oil firing until the recent fuel shortages.

Any technique that improves the overall performance of the stoker will minimize smoke, particulate, CO, and gaseous hydrocarbons emissions although it may increase NO_x emissions. Some of these techniques include

- Overfire air jets--to improve mixing above the fuel bed

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* The Federal standard[8] for particulate emissions from large boilers is 0.1 lb/10^6 Btu-hr of input while state standards[9] range from 0.1 to 0.8 lb/10^6 Btu-hr, largely depending upon the heat-input rating.

- Zoned-air admission--to provide a control of the air/fuel ratio over the entire grate and produce uniform burning of the entire fuel bed
- Reduction in excess air level--reducing air velocity through the bed minimizes bed disturbance and fly ash carryover. Also, this technique increases boiler efficiency.
- Although not utilized in industrial stoker applications, afterburners, either oil or gas-fired, used just above the fuel bed can reduce emissions associated with incomplete combustions.

RESEARCH PROGRAM

PHASE I. EVALUATION OF ALTERNATIVE COALS

The prime objective of this phase of the research program is to evaluate the emissions resulting from the combustion of untreated, reconstituted, and processed coal in a small-scale stoker. Two types of stokers will be used: (1) a commercially available underfeed stoker and (2) a model spreader stoker.

The evaluation of emissions from the combustion of candidate stoker coals will be strongly related to design and operation of the stoker. Certain chemical and physical properties of the coal are more critical for one type of stoker than for another. For example, the spreader stoker can fire most caking coals successfully while the underfeed stoker cannot. Likewise, a very low-volatile coal like anthracite cannot be fired in spreaders (unless mixed with another type of fuel) but can be fired in either an under- or over-feed stoker. Accordingly, the basis for the coal evaluations will be expanded by the use of two stokers.

The spreader stoker was selected because this type will be used during Phase II and its use in Phase I will provide data for Phase II planning. As previously discussed, the spreader has been demonstrated as one of the most effective methods of direct firing of coal in intermediate size equipment. The underfeed stoker was selected because (1) it is representative of smaller industrial stokers, (2) it is part of an existing stoker-boiler facility that can be operated immediately, and (3) significant data already exists for selected coals.

Candidate Coals

Coals to be considered are untreated, reconstituted, and processed. The untreated coals will be representative stoker fuels and/or have low pollution potential based on natural analysis. These coals are commercially available. The reconstituted coals (physically treated) and the processed coals (chemically treated) are coals that have been treated to obtain the desired properties of a low emission fuel. These coals will be prepared at Battelle-Columbus or at an ongoing processing facility. The reconstituted and the processed coals will require some preparation for stoker firing (either briquetting or pelletization) as these coals are produced in powdered form.

Untreated Coals--

From a pollution standpoint, properties of coals most suitable for stoker firing include

- Ash content - about 5 percent
- Sulfur content - less than 1 percent
- Nitrogen content - less than 1 percent
- Volatile content - less than 25 percent
- Moisture content - less than 10 percent
- Fusion point of ash - greater than 2500 F
- Free swelling index - less than 5.

There are few coals that possess all of these properties. In addition, some of these properties are not critical to operation of certain types of stokers.

For example, the overfeed stoker, typified by the chain, traveling, vibrating, or pulsating grates, produces the minimum particulate emissions because of the relative quiescence of the fuel bed. However, these stokers are usually limited to noncaking or very weakly caking coals; those having a low Fr

Swelling index, in the range of 2 to 4. More strongly caking coals (such as those of Ohio, West Virginia, and Pennsylvania coals) produce caked masses on the moving grate and poor distribution and flow of primary air results. Coals from Indiana, Illinois, and farther west are generally weakly caking and burn uniformly, but have sulfur levels as much as 3 to 4 percent.

The spreader stoker projects the coal particles into the high temperature furnace so that the hot flame gases destroy the surface-caking tendency. Thus, as the heavier burning particles fall to the grate they form a porous, uncaked bed through which primary air can flow uniformly. Thus, the spreader stoker is the most versatile of all stokers; it can burn a broad range of coals as well as many combustible industrial wastes, such as bark and bagasse. Also, with a continuously moving fuel bed the spreader stoker can generally handle much higher ash and moisture content than the underfeed stoker (which also is adapted to burning caking coals). Two drawbacks of the spreader stoker are inherently high particulate emission and a tendency to smoke below about 35 to 40 percent of full load.

However, for the highly versatile spreader stoker, all coals are "typical". Low ash content is preferable to minimize loss of fly ash.

For the underfeed stoker, the eastern or mid-western caking or milding caking coals are "typical". Low ash is also preferable to minimize the labor of clinker removal.

A few low-sulfur, strongly caking coals are available in the East, but most of these are captive for metallurgical use. In general, small users seeking low sulfur coals must look to western coals.

Reconstituted Coals--

Little work has been done in recent years on briqueting or pelletizing coal, screening operations at the mine being adequate to provide coal of the proper size for industrial users. In earlier times, and particularly in Europe, briqueting was common, mainly for producing domestic fuels. In Germany, for example, low-rank coals were briqueted without the addition of binder by using ring-roll presses with sufficiently high compression forces that the coal particles adhered tightly to one another. In the United States during the 1940's, a form of briquet called "packaged fuel", consisting of 4-in. cubes, was prepared on a commercial scale to utilize No. 4 buckwheat anthracite by blending it with bituminous coal for hand-firing in domestic furnaces. A small amount of starch binder was used to stabilize the cubes until they were fired, when the caking characteristics of the bituminous-coal portion helped agglomerate the anthracite fines into a relatively free-burning fuel bed. At the end of the war, with a return to a normal fuel supply situation, production of packaged fuel was stopped. Economically, briquetting could not compete with sized raw coal in a normal economy.

In Korea, the major occurrence of coal is a friable type of anthracite which is converted into a useful form by briquetting it, with clay as the binder, into cylinders roughly six inches in diameter and six inches high. These cylinders are pierced longitudinally with half-inch holes, leading to the descriptive name of "nineteen-hole briquet". In 1966, more than 7 million tons of such briquettes were burned in Korea, mainly for domestic heating and for cooking. The clay binder is added to maintain integrity of the briquettes both during handling and during burning. The briquettes burn cleanly, and essentially all the combustible is utilized over a four- to six-hour period.

Pelletizing to dispose of coal fines has been tried in the United States(10) to convert 28-mesh x 0 filter cake or slurry from coal preparation plants into a product with combustion characteristics essentially the same as the original coal with the same size consist. A wet binder, typically a lignin derivative from the paper industry, amounting to about one percent of the weight of the coal, produced adequately strong pellets. Estimated operating costs in 1957 were $1.08 per ton of coal pellets, an unrealistic figure today. It is evident, based on these experiences, that reactive additives are not necessary to pelletize or to briquet most coals. There is the additional factor today of deliberately adding a reactive component to coal briquets or pellets to capture sulfur during combustion or to lower the resistivity of the resulting fly ash. The most attractive sulfur-capturing agent is limestone which could be easily incorporated as a 200-mesh slurry into briquets or pellets. To maximize compression strength of the product, $Ca(OH)_2$ would be better but also much more costly. A major problem here is that for reasonable effectiveness, the fuel-bed temperature must not exceed about 1800 F because $CaSO_4$ decomposes into CaO and SO_2/SO_3 when the temperature is higher. Hence, there would be no advantage in having lime present if normal fuel-bed temperatures were reached. Another problem is that lime is an effective flux for the ash in coal, reducing the fusion temperature markedly and, thus, leading to increased clinker formation.

Addition of Na_2CO_3 to coal has been shown to catalyze gasification reactions, and it is evident that the alkaline can improve combustibility. Also Na_2CO_3 lowers the electrical resistivity of fly ash thereby making fly ash easier to collect in an electrostatic precipitator. But the alkalies are also potent fluxes for coal ash and they are the major factor in causing fouling of heat-receiving surfaces, such as wall tubes, superheater, and reheaters. In large boiler furnaces, as for the public utilities, increase in the alkali content of coal would be objectionable; it is not known whether this same objection would apply to spreader or to underfeed stokers in industrial plants.

No fuel treatment systems are known at present that apply coatings to fine sizes of coal. Surface treatment of screened coal has been used in the past to minimize dust and to prevent freezing in transit, but these have been typically light mineral oils and calcium chloride. Alkaline earth and alkali metal compounds might be applied to coal fines with the reservations noted earlier about increased clinker formation and fouling tendency, particularly if appreciable amounts of such treatment were applied. Small quantities of treatment definitely can control a dust nuisance during handling, but the limits are not closely defined for today's technology and problems.

The characteristics of coal ash vary so widely that it is difficult to generalize about such factors as acid leaching. Low-ash-fusion coals often contain appreciable quantities of pyrites, FeS_2, which may remain only partially oxidized in clinker from industrial boiler furnaces. Such clinkers, when exposed to weathering, may release sulfuric acid by further oxidation of the pyrites, just as acid mine water is formed. Also, SO_3 in flue gas can condense on fly ash, leading to acid leaching. There is at least a fair likelihood that chemical treatments can be derived to neutralize clinker and fly ash to eliminate acid leaching, but the most effective route would seem to be by treating the products of combustion rather than the coal. Applying sealing coats to the surface of the clinker or fly ash would appear to be less desirable than chemical neutralization, but this needs to be evaluated.

Processed Coals

Processed coal is defined as a coal or solid fuel derived from coal which has been chemically cleaned for the purpose of removing at least a part of the pollutant forming constituents such as sulfur, nitrogen, and ash values including the toxic metal values. During the treatment, the coal structure may also be modified or altered which may improve the combustion characteristics of the coal.

Solvent Refined Coal--

An example of a chemically cleaned coal is solvent refined coal. In this case, a significant portion of the sulfur and ash including the toxic metals are separated from the coal by selective solubilization of the coal in an organic solvent. After separation of the solubilized coal from the residual ash and a sulfur, a solid fuel referred to as solvent refined coal is obtained by evaporation of the solvent. This solvent refined coal with a melting point of several hundred degrees Farenheit, represents a solid fuel in which the coal structure has been modified or altered since the coal was actually solubilized during the chemical cleaning operation.

Solvent-refined coal (SRC) offers a unique opportunity for controlling sulfur and particulate emission, but its handling and combustion characteristics are still not well enough known to permit prediction of its suitability in industrial boiler furnaces. Preliminary work done for the Electric Power Research Institute by Babcock & Wilcox(11) demonstrated that the ignition of pulverized SRC should be similar to a high volatile bituminous coal while the burnout temperature is similar to a low volatile bituminous coal or an easily burned anthracite. Hence combustion in pulverized form should pose no serious problems. Because SRC tends to become tacky at temperatures as low as 300 F, special precautions are necessary in pulverizing it. Emission of NO_x has been high because SRC has a high fuel-bound nitrogen content, but SO_2 emissions are low since SRC contains much less sulfur than the original coal.* Emission of particulates also is low because the ash content is generally well under one percent. However, about 4 to 5 percent ash is desired because the coal ash protects the stoker grate from overheating.

Probably, because of its low melting point and low-ash content, SRC will not be adaptable to stokers, either spreader or underfeed. However, at 410 F, SRC has a sufficiently low viscosity for pumping like residual fuel oil, and at 540 to 580 F it can be atomized successfully. Thus, since its combustibility apparently is equivalent to that of pulverized coal, and since it can be handled much like a heavy residual fuel oil, there is an excellent chance that SRC can be adapted to industrial boiler furnaces as a liquid fuel.

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* Apparently SRC does not remove any fuel nitrogen.

TRW Coal Meyer's Process--

Another example of a processed coal is that produced by the TRW process. In this process, the sulfur and possibly some of the ash is selectively extracted and separated from the coal matrix in contrast to solvent refining in which the coal is selectively extracted from the ash. The resulting chemically cleaned coal, i.e., that produced by the TRW process, may behave quite differently in stoker firing because its structure has not been altered to the same extent as the solvent refined coal. However, because of the removal of a portion of the pollutant forming constituents, the TRW coal should have a lower emission factor than that of raw (untreated coals) and may also be more reactive.

Battelle-Columbus -- Hydrothermal Treated Coal (HTT)--

The Battelle-Columbus' hydrothermal-treated coal process includes heating an aqueous slurry of coal and chemical leachant at moderate temperatures and pressures to extract sulfur and some of the ash from the coal. Further applicability of this process may be achieved since in one alternative of the process the solid fuel is impregnated with lime, a sulfur-getting chemical in the desulfurization operation. During the combustion process, the alkali -- part of the coal structure -- reacts with part of the remaining sulfur in the clean solid fuel to produce nonvolatile sulfur compounds which remain with the fuel. Another feature of the HTT process is the extraction of a number of potential toxic or hazardous metal values from the coal, many of which might normally be discharged into the atmosphere with the products of combustion.

Briquetting/Pelletizing--

Stoker fuel may be prepared from solvent refined coal by one of several methods. The simplest method would entail briquetting in which the coal is compacted into briquets of the desired size. Because of the nature of the coal -- low melting point -- the addition of a binder will most likely not be necessary. Grinding or milling prior to briquetting may be required depending on the size of the particles or pieces from the solvent removal operation. Stoker fuel may also be prepared by pelletization either during or after removal of the solvent. Pelletization may be achieved during removal of solvent by conducting the solvent removal operation in a rotating drum arrangement. In this case, the addition of a binder would, most likely, not be required. Furthermore, grinding or milling of the fuel would not be required as the pellets would be formed during the solvent removal step.

The solvent refined coal may also be pelletized after removal of the solvent. In this case, the coal would be ground to a desired particle size, probably about 100 percent minus 100 mesh. The ground coal would then be tumbled in a rotating drum to form the pellets of the desired size. The addition of a binder will not be necessary if the coal is heated slightly. On the other hand, a binder such as water or an organic solvent may be mixed with the coal prior to pelletization.

Stoker feed may be prepared from TRW coal and the HTT coal by briquetting and/or pelletizing. In both cases, the addition of a binder may be necessary. Briquettes of sufficient mechanical strength may be prepared by compacting a mixture of the chemically cleaned coal and a binder such as water into the desired size. Other candidate binders include sugar solutions and coal tar. Pellets of the TRW and HTT coal chemically cleaned coal may be prepared by the same method as used in pelletization of the solvent refined coal. In this case, the chemically cleaned coal before drying may be tumbled in a heated rotating drum to form the pellets and evaporate the water. If stronger pellets are desired, the coal may be heated to a temperature just below or near the softening point of the coal, approximately 500 to 600 F. On the other hand, strong pellets may be formed by the use of sugar solutions or coal tar as the binder.

Experimental Systems

A commercial 20 hp hot-water stoker-fired boiler capable of firing coal at rates up to 75 lb/hr will be utilized during Phase I. Currently, the boiler is fired by an underfeed stoker. This facility has suitable controls so that the stoker-boiler can be operated unattended under conditions typical of commercial stoker operation. Combustion gases are vented through a 14-in. insulated stack that includes provision for sampling (4 ports) at a location 10 stack diameters downstream of the boiler outlet. The stack has additional ports for gaseous emissions and smoke determination. Bottom ash residues can be collected through the firebox door. If this procedure is found not to be satisfactory, a minor modification in the boiler setting will be made so that ash samples can be collected without disrupting the operation of the stoker.

It is considered difficult to project the effect of some important coal properties on combustion in a spreader stoker, based on underfeed stoker data. The two types of stokers provide radically different burning methods (suspension plus bed burning versus entirely bed burning) and even have opposite coal and air flow patterns (counterflow versus parallel flow). Thus, as discussed earlier, to make the results of Phase I more relevant to Phase II and more applicable to industrial stokers, this small stoker will be modified to operate as a spreader stoker for most of the Phase I studies. A feed system similar to that of a spreader stoker will be installed through the firebox door and the boiler setting will be modified to accommodate a new grate. Other elements of the facility will remain the same.

Environmental Impact

From the results of the Phase I program, an assessment will be developed that will include defining the complete pollution potential for untreated, reconstituted, and processed coals for improving the environmental acceptability of stoker-boiler technology. This assessment will also relate the results of the small-scale stoker-boiler investigation to larger scale stoker boilers.

PHASE II. CONTROL TECHNOLOGY EVALUATION PROGRAM

The prime objective of this phase of the research program is to identify and evaluate potential concepts for control of emissions for full-scale industrial stoker boilers. In this phase of the program, control strategies are limited to modifications in the design and operation of the stoker and to firing of low pollution coals (either naturally occurring or those that have been chemically or physically treated). Research on flue gas clean-up equipment will not be investigated.

The experimental research will be conducted in the Battelle-Columbus steam plant 600-hp spreader stoker boiler facility. In addition, Battelle-Columbus plans to consider the evaluation of potential control techniques in the small scale system, if deemed appropriate, prior to evaluation in the larger stoker boiler. If technically feasible or practical, utilizing the smaller system to screen potential control concepts can be accomplished at a significantly lower rate of expenditure than in the larger system.

Experimental Boiler and Control Equipment

The investigation and demonstration will be conducted in a water-tube boiler (approximately 600 hp) having a 25,000 lb/hr steam capacity that has been recently converted to stoker firing. This boiler, a Keeler Type HDB, was designed for coal firing but until recently has been fired on oil and gas. The stoker is a Hoffman spreader-type with a vibrating grate. The facility is designed with a fly-ash reinjection system to promote carbon burnout and, thus, to increase boiler efficiency. In addition, the installation includes a UOP Multiclone mechanical dust collector for particulate control and complete coal-handling and ash-disposal systems.

The stoker installation was designed to include provision for a moderate amount of modification, thus minimizing modification costs. Additional instrumentation such as pressure gages, thermocouples, flow meters, will be installed in the stoker-boiler system where needed to provide for measurement of pertinent stoker and boiler operating parameters. Damper and valve positions will be calibrated to determine flow rates.

Ports for gaseous emissions, smoke opacity, and particulate loading measurements will be provided. In addition, provisions will be made to sample fly ash from the dust collector and from the settling chambers ahead of the dust collector, the grate-ash residue, and the grate-ash siftings.

Candidate Fuels

Providing that one or more of the treated fuels gives definite pollution control results with reasonable economic potential, a quantity of the best formulation ("designed fuel") will be prepared in sufficient quantities to permit Level 1 and Level 2 environmental assessment sampling and analysis work. The 600-hp stoker boiler fires over a ton of coal per hour so availability of the various treated fuels will have to be a factor in fuel selection.

Potential Experimental Conditions

Table II outlines potential operating variables for the Phase II program. As in Phase I, criteria pollutants can be utilized to screen the various operating conditions. It is envisioned that this experimental program can be conducted in the following five parts.

1. Baseline Performance. Emission (and efficiency) measurements, plus other observations, will be made and analyzed for this system firing several coals and size distributions under a variety of operating conditions to establish characteristic baseline performance. These tests will establish baseline data and document the effect of coal parameters on performance of this stoker, particularly as they relate to modern emission standards.

Table II includes an outline of pertinent variables (and the resulting potential operating conditions). Of these, the coal type will be the most dominant in affecting the performance of the stoker-boiler system. Consideration will be given to high volatile, caking coal as this type of coal is one of the more difficult coals to burn with a stoker. From a research viewpoint, it would be of interest to investigate a low-volatile coal, about 20 percent volatile matter, but these coals are generally used for metallurgical purposes and are not fired in industrial boilers.

Generally, coals available for stoker firing will have a narrow range of volatile matter. However, other pertinent coal properties that affect smoke generation, fly ash emissions, and slag or clinker formation are

- Coal size
- Ash content
- Ash softening temperature.

These coal properties will be investigated to determine their effect on boiler performance and air pollutant emissions, while varying overfire air rates, boiler loads, excess air levels, and fly-ash reinjection rates. Because low-load smoke is an acute problem of the spreader-stoker, an additional effort will be expended at this condition.

Because the facility will be well-instrumented, gaseous and smoke emission (as well as boiler operating performance data) can be recorded continuously and encompass many test points. In addition, it is planned to collect particulate samples at selected test conditions. These particulate samples, the continuously recorded emissions and boiler operating data, plus various coal and ash analyses, will provide ample baseline data from which to characterize this system under a variety of conditions. From these, the most practical conditions will be selected for baseline Level 1/Level 2 measurements.

Task 2a. Modification of Stoker Operation. Based upon the results of Task 1 (Baseline Performance), modification in the operation of the stoker (specifically, the overfire air and fly-ash reinjection systems) will be investigated under those conditions that are found to be environmentally unacceptable. These findings will provide a basis for suggesting modifications in the stoker operation to achieve a reduction in emissions and an improvement in overall stoker-boiler performance. However, it is anticipated that modifications in stoker operation to reduce low-load smoke will need consideration. Accordingly, an optimum coal will be selected to explore the effect of:

- Overfire jet modifications
  - Jet temperature
  - Jet quantity and velocity
  - Jet orientation
- Steam injection above bed

to find their effects on low-load smoke.

An additional consideration will be to optimize fly-ash reinjection rates and to optimize the ratio of primary and secondary air flow rates as a function of boiler load. Also, from a boiler efficiency viewpoint, a minimum excess air level will be established and the characteristics of slag formation and emission generation will be investigated at this excess air condition. Criteria pollutant data will be collected during these runs.

2b. Modification of Stoker System. The stoker-boiler system will be modified to evaluate the emissions control improvement by the various control strategies. Table II summarizes candidate control strategies. Other promising techniques identified during the program will also be considered. Criteria pollutant data will be collected.

3. Evaluation of Particulate Control Equipment. The multistage cyclone will be evaluated for its fly-ash control capability. Because the cyclone is coupled directly to the boiler outlet, it is not possible to sample upstream of this device. The collection efficiency of the cyclone will be determined [illegible] comparison of the collection of fly ash in the cyclone to the fly ash collected in the flue gas immediately downstream of the cyclone.

4a. Conditions for Level 1/Level 2 Sampling and Analysis. Emissions of all Level 1 pollutant groups and specific Level 2 pollutants expected to be responsive to control parameters shall be determined for each major modification. The criteria pollutant data (where appropriate) will serve as an indicator to determine whether Level 1/Level 2 pollutants will be responsive to modifications.

(2). Level 1/Level 2 Methodology. The industrial stoker that will be used in this program is much more complicated than the small stoker, as can be seen in Figure 6. It is planned to conduct a complete fireside Level 1 sampling and analysis run for the industrial boiler for each coal fired. However, as previously mentioned, adequate Level 1 (and Level 2, if necessary) data on the waterside streams will be forthcoming on another EPA program (Contract No. 68-02-2197). Thus, we plan not to sample waterside streams for this combustion study.

Considering the fuel-side streams, only four streams actually flow into or out of the unit. These are the air, coal, ash, and flue gas streams. We will not sample the combustion air stream. Although there are four separate ash collection points, the collected ash is either reinjected into the furnace or is combined into one ash stream for disposal. The coal and ash streams actually operate on a batch basis, rather than continuously. Coal is fed into the hopper until the hopper is full and then no coal is fed until the coal in the hopper is nearly all consumed. Likewise, ash is typically discharged to the ash holding tank about once during each shift. A number of coal and ash samples will be obtained during the coal feeding and ash discharge operations to insure that the coal and ash samples are reasonably representative of the bulk material. Applicable ASTM procedures will be used for this sampling. The individual samples will be combined into a single sample for each run for Level 1 and appropriate Level 2 analyses.

During the Level 1 sampling run of each fuel, Level 1 sampling of the flue gas will be conducted. This will include sampling with a SASS sampling train and other sampling systems, as necessary, to obtain complete Level 1 data. A complete Level 1 analysis will be conducted on the samples. Level 2 analysis will be conducted for pollutants expected to be strongly influenced by fuel and/or operating conditions (notably POM).